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NATURAL GAS

HEARING

BEFORE THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES UNITED STATES SENATE

ONE HUNDRED TWELFTH CONGRESS

FIRST SESSION

TO

RECEIVE TESTIMONY ON THE RECENT REPORT OF THE MIT ENERGY INITIATIVE ENTITLED "THE FUTURE OF NATURAL GAS"

JULY 19, 2011

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NATURAL GAS

TUESDAY, JULY 19, 2011

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, DC.

The committee met, pursuant to notice, at 10:35 a.m. in room SD–366, Dirksen Senate Office Building, Hon. Jeff Bingaman, chairman, presiding.

OPENING STATEMENT OF HON. JEFF BINGAMAN, U.S. SENATOR FROM NEW MEXICO

The CHAIRMAN. OK. Why don't we get started? Thank you all for being here.

In recent years a number of factors have combined to raise the prominence of natural gas as a resource. Let me mention 5 of those factors.

The first, the new application of technologies such as horizontal drilling and hydraulic fracturing have led to an increase of domestic natural gas production and a reassessment of the size of the U.S. technically, recoverable resource base.

Second, the international focus on reducing greenhouse gas emissions to address climate change has favored the lower carbon intensity of natural gas for power generation.

A third factor is the recent tragedy in Japan at the Fukushima Nuclear plant that's led both the Japanese and German officials to speak strongly about fuel switching to natural gas to replace or at least supplement their remaining nuclear fleet.

The fourth factor is concerns about our dependence on foreign oil have led some to propose switching to more use of natural gas in the transportation sector in our cars and trucks and as a substitute for diesel fuel.

The fifth factor is that proponents of domestic manufacturing have argued that a larger, more stable gas supply at competitive prices will lead to a resurgence of investment in manufacturing and job creation which is very much desired by, I believe, all of us.

So in the past several years there's been an increase in the estimates of natural gas resources available at relatively low prices leading many experts to suggest that we may now be entering a "golden age of gas." I'll leave the specifics of those projections to our witnesses. But in general I think there is agreement that there's a greatly expanded, unconventional gas resource available domestically with potentially 100 years or more in gas available if current rates of usage are maintained. This change in the resource base has already had significant impacts on investment decisions in the power sector, in manufacturing and in transportation and many expect that it will continue to have an impact on decision-making in these and other areas in the future.

There are many reasons to be optimistic about the natural gas resource that has recently been discovered. But recent history suggests we should be cautious as well. During the 1990s, for example, projections of a high supply of natural gas at low prices led to tremendous investments of new natural gas fired capacity for electricity generation and much of that capacity continues to be underutilized today.

During the early 2000s the optimism over supply was replaced by the concern that we would not have enough natural gas. As a result significant investments were made in infrastructure to import liquefied natural gas from other countries. Those import terminals now operate at very low capacity as a result of the current low price of domestically produced natural gas.

The promise of expanded domestic gas resources comes with the responsibility to address environmental concerns that relate to the exploration and production of the gas. Recently the public has expressed concerns about the waste water management of flow back fluids from natural gas wells, as well as the potential for ground water contamination.

The issue of induced seismicity has also been raised in connection with oil and gas extraction related activities in Texas and Arkansas. The National Academy of Science is undertaking study at Secretary Chu's request and my request.

I expect that the environmental concerns related to developing unconventional gas resources can be managed, but only if they are addressed through a transparent, diligent and safe approach to well site management through each stage of the gas extraction process. The hearing today is intended to shed light on many of these high level issues about the current and future role of natural gas in meeting our energy needs.

We have an excellent panel of witnesses. Before I introduce them let me call on Senator Murkowski for any opening statement she'd like to make.

STATEMENT OF HON. LISA MURKOWSKI, U.S. SENATOR FROM ALASKA

Senator MURKOWSKI. Thank you, Mr. Chairman. I appreciate you scheduling the hearing today. Special thanks to our witnesses for joining us today.

I do appreciate the chance to learn more about MIT's recent study and to spend some time thinking about the future of one of our Nation's most promising resources. Natural gas is clean burning and abundant. It's well understood. It's scalable. It's clearly in our best interest to ensure that we maintain a stable and affordable supply going forward.

I think one of the easiest observations to make is that we're now in the midst of a very exciting time for the natural gas industry. Just in the past several years, we've witnessed game changing technological innovations that have unlocked tremendous volumes of previously inaccessible natural gas. These resources are already benefiting our Nation by further diversifying our energy supplies and creating thousands and thousands of well paying American jobs.

This is even more remarkable when you consider that just 3 or 4 years ago, we were facing a very, very different situation. If this was 2005, our opening statements here in this committee would probably have expressed at least some concern about our ability to ensure that supply kept pace with demand. Prices were trending higher and many forecasts suggested that we become increasingly dependent on foreign LNG.

Today, however, new applications of technologies such as horizontal drilling and hydraulic fracturing have significantly shifted that picture. At moderate cost our vast natural resources, our natural gas resources, can meet the most aggressive projections of demand and amount to more than 100 years of supply at today's consumption rates. Of course I think that every member of this committee is very well aware of my strong interest in helping Alaska bring its huge resources, its reserves of natural gas to market. But I think you should also know that I made a decision very early on to encourage the expanded development and transportation of natural gas all throughout our country, even though many felt that the shale gas revolution would be bad for Alaska's prospects.

There are 2 reasons for this.

The first is that it is still the right thing for Alaska, as I believe that we will ultimately have an easier time selling our gas to a Nation that has built a larger market and infrastructure for gas fired power and gas fired vehicles. That's within reach right now.

The other reason why I'm such a strong supporter of shale gas is that it's simply the right decision for our country as a whole. Natural gas was once thought of as too precious to burn. But that has changed, and I think for the better.

When I look at the deeply troubling situation in North Africa and the Middle East, I don't see a future where we can afford to play politics with energy at the national level. The rest of the world has already figured that out. I'm hopeful that we will begin to see this reality as well.

I'd like to add that developing all of our resources in a responsible way is of paramount importance. Natural gas is no exception. We cannot realize the many benefits of our tremendous natural gas resources unless we commit to safe, environmentally acceptable production and delivery within a framework of appropriate regulation and access. Contrary to some reports the industry actually has a very exemplary record in this regard. I welcome its efforts to proactively seek ways to increase transparency and improve the efficiency of the extraction process.

Mr. Chairman, I again thank you for organizing this hearing. Many of our members, myself included, are champions of natural gas. Greater use of natural gas would move our Nation in the right direction in terms of energy security, economic growth and environmental protection. Those are 3 critically important goals. Every one of them is possible, I believe, thanks to our Nation's vast natural gas resources.

I look forward to the comments that we will hear in the presentation from our witnesses this morning.

The CHAIRMAN. Thank you very much.

Let me introduce our witnesses.

First is Dr. Howard Gruenspecht, who is the Acting Administrator and Deputy Administrator with the U.S. Energy Information Administration. He's a frequent witness before our committee. Welcome, again today. We appreciate all the work you've done on this important issue.

Dr. Ernest Moniz, who is the Cecil and Ida Green Professor of Physics and Engineering Systems at MIT, also the Director of the MIT Energy Initiative and the Chief Author of the new report that he's going to talk about today related to natural gas. We very much appreciate you being here.

Mr. George J. Biltz is the Vice President for Energy and Climate Change with Dow Chemical Company. We very much appreciate you being here.

So why don't each of you—I think we'll have more leeway in the timing today take 5 to 10 minutes presenting your testimony. Give us the main things you think we need to understand about the importance and future of natural gas in meeting our energy needs. Then we'll have some questions.

Dr. Gruenspecht, why don't you start.

STATEMENT OF HOWARD GRUENSPECHT, ACTING ADMINISTRATOR, ENERGY INFORMATION ADMINISTRATION, DEPARTMENT OF ENERGY

Mr. GRUENSPECHT. Mr. Chairman, Senator Murkowski, members of the Committee, I appreciate the opportunity to appear before you today. The Energy Information Administration is a statistical and analytical agency within the Department of Energy. The EIA does not promote or take positions on policy issues and is independent with respect to the information and analysis we provide therefore our views should not be construed as representing those of the Department or other Federal agencies.

It's pretty obvious that U.S. natural gas markets have recently experienced significant change. After a decade of stagnation, domestic dry gas production increased almost 17 percent between 2006 and 2010, largely driven by the growth in shale gas production which increased more than 4 fold over this period. In 2010 shale gas accounted for 23 percent of total U.S. natural gas production. Natural gas continues to provide about 25 percent of total U.S. energy use with current consumption spread evenly across buildings, industrial use and electric power generation. There's a small amount of use for transportation, mostly as fuel for pipelines and I know there's a lot of interest in transportation applications more broadly.

With production growing at a faster rate than consumption, U.S. natural gas imports in 2010 were at their lowest level since 1994 having declined from roughly 16 percent of U.S. natural gas consumption in 2007 to under 11 percent of consumption. Wholesale natural gas prices averaged $4.37 per million Btu in 2010 close to their level a decade earlier after adjustment for inflation.

Earlier you were discussing the ups and downs of natural gas. I remember well I came to EIA in March 2003 when natural gas storage at the end of that winter was very low. Chairman Greenspan spoke about natural gas and the fact that we'd be relying on

LNG. So there have been a lot of ups and downs. I guess I came in on a down and now we're in a different place.

On an energy equivalent basis, natural gas is trading at a deep discount to oil, with oil prices now more than 3 times higher than natural gas prices. With almost all easy opportunities to switch from oil to natural gas in industry, buildings and electric power generation having already taken place, the most active fuel switching area for natural gas today involves competition between natural gas and coal as a fuel for electric power generation.

As discussed in my written testimony, reserves data and growing resource estimates suggest continued opportunities for future production growth.

Turning to a longer term view, EIA projects that total natural gas production will grow by 26 percent between 2009 and 2035. Shale gas constitutes about 47 percent of total U.S. dry gas production in 2035 in our reference case projections.

Natural gas production costs and prices are projected to rise over time as production shifts away from the most attractive "sweet spots" to less productive areas. Counter balancing that will be the presumably continued advance of technology. Average annual wholesale natural gas prices remain under $5 per million Btu in real 2009 dollars through about 2020.

As shown in Figure 4 of my written testimony, the ratio of oil-to-natural gas prices in energy equivalent terms remains above 3 on an annual average basis in our reference case projection as the balance of gas supply and demand within North America limits natural gas price increases at a time when the world supply/demand balance for oil is expected to push oil prices up at a faster rate.

EIA fully recognizes uncertainties surrounding our reference case natural gas projections. Shale gas uncertainties are addressed in a prominent special section of our 2011 Outlook that is discussed in my written testimony. As shown in Figure 5 of that testimony, the shale gas cases illustrate how the underlying uncertainty regarding the extent of this emerging resource and the costs of developing it translates into a wide range of production and price projections.

Shown in Figure 3 and 6 of my written testimony, natural gas demand is projected to grow over 16 percent between 2009 and 2035 with the industrial and electricity generation sectors as the main drivers of future demand growth.

My testimony also discusses a number of significant uncertainties affecting the demand side of the natural gas market. For example, several factors including regulatory changes could increase the use of natural gas in the electric power sector. Our 2011 Outlook includes several cases that look at the sensitivity of the generation mix and coal retirements to different assumptions regarding the price of natural gas, the extent and cost of retrofits required for existing coal fired facilities and the recovery period for retrofit investments. A scenario that combines significant retrofit requirements, insistence of the owners on rapid payback of retrofit costs and continued low natural gas prices results in significant near term retirements of existing coal plants and more use of natural gas for generation.

Another demand uncertainty involves the increased use of natural gas as a transportation fuel. In the 2010 edition of the Outlook, EIA included sensitivity cases that explored the impact of significant incentives to promote the use of natural gas as a fuel for heavy duty trucks.

A third significant uncertainty involves the potential that the North American market for natural gas could become more fully integrated into the global market for natural gas. Ultimately such a possibility will depend on the extent of natural gas trade between North America and the rest of the world. I think there are several important issues there.

One relates to the developments in shale gas in the rest of the world. That's something that EIA has been looking at because of the effect that will have on potential trade.

The other involves the nature of the pricing of liquefied natural gas in the global marketplace, the extent to which you have gas on gas competition or whether LNG maintains its traditional link to oil prices.

That concludes my oral statement, Mr. Chairman. I would be happy to answer any questions you or the other members might have. Thank you very much.

[The prepared statement of Mr. Gruenspecht follows:]

PREPARED STATEMENT OF HOWARD GRUENSPECHT, ACTING ADMINISTRATOR, ENERGY INFORMATION ADMINISTRATION, DEPARTMENT OF ENERGY

I appreciate the opportunity to appear before you today to address current and projected supply and demand conditions for natural gas.

The Energy Information Administration (EIA) is the statistical and analytical agency within the U.S. Department of Energy. EIA collects, analyzes, and disseminates independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding regarding energy and its interaction with the economy and the environment. EIA is the Nation's premier source of energy information and, by law, its data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views expressed in our reports, therefore, should not be construed as representing those of the Department of Energy or other Federal agencies.

My testimony today addresses the hearing topic by providing a brief overview of recent natural gas developments, EIA's evaluation of U.S. natural gas reserves and resources, and a discussion of our natural gas projections to 2035 and some of the key uncertainties surrounding them.

Overview of recent U.S. natural gas data

Production—After a decade of stagnation, U. S. natural gas production increased by almost 17 percent between 2006 and 2010, reaching 21.6 trillion cubic feet (Tcf) in 2010, the highest level since 1973. Production has continued to increase despite a significant and sustained decline in natural gas prices since mid-2008.

The growth in U.S. supplies over the past few years is largely the result of increases in production from shale gas formations. Shale gas production grew from less than 3 billion cubic feet per day (bcf/d), representing 5 percent of overall production in 2006, to 13 bcf/d, accounting for 23 percent of overall production in 2010.

Imports—Increased domestic production has greatly diminished the Nation's need for natural gas imports, while lower prices have reduced foreign producers' incentive to supply the United States. In 2010, net imports to the United States dropped to 2.6 Tcf, representing 10.8 percent of U.S. consumption, marking the lowest volume of net imports since 1994 and the lowest percentage since 1992. As recently as 2007, net imports were the highest on record, equaling roughly 16 percent of consumption.

Demand—Natural gas has long played an important role in meeting U.S. energy needs. The main uses of natural gas are in buildings, the industrial sector, and electric power generation. Natural gas provides about 25 percent of the primary energy used in the United States, heating about half of U.S. homes, generating almost one-fourth of U.S. electricity, and providing an important fuel and feedstock for industry. About 31 percent of the natural gas consumed in 2010 was used for electric power generation, 33 percent for industrial purposes, and 34 percent in residential and commercial buildings. Only a small portion is used in the transportation sector, predominately at pipeline compressor stations, although some is used for vehicles.

Demand for natural gas in buildings, and to a lesser extent in the electric power sector, is highly responsive to weather conditions, for space heating and air conditioning. In the industrial sector natural gas demand is more responsive to economic conditions, as illustrated by that sector's decline in natural gas use in late 2008 and 2009. However, the sector has rebounded with consumption in 2010 returning to essentially the same level as that in 2008.

Prices—In 2010 wholesale (Henry Hub) natural gas spot prices averaged $4.37 per million Btu, close to the level a decade earlier after adjustment for inflation. On an energy-equivalent basis, natural gas has traded at a deep discount to oil over the last several years with oil prices more than 3 times higher than natural gas prices. Almost all easy opportunities to switch away from oil use to natural gas in industry, buildings, and electric power generation have already taken place or are being actively pursued. For example, in 2010, oil provided less than 1 percent of total electric power generation. Increasingly, the most important area for fuel switching involving natural gas is the competition between natural gas and coal as a fuel for electric power generation.

Drilling activity is also responding to the differential between oil and natural gas prices with the number of oil-directed rigs having recently exceeded natural gas-directed rigs for the first time since 1993. However, as noted above, domestic production of natural gas has continued to increase despite the renewed focus on drilling for oil. This reflects both the high productivity of current gas-directed drilling and the fact that oil-directed drilling activity often results in production of associated natural gas as well as oil.

Reserves and Resources—U.S. total natural gas proved reserves grew 11 percent in 2009 and are now at the highest level since 1971. Shale gas proved reserves grew 76 percent after having grown by 48 percent in 2008, reflecting continued strong drilling activity even as natural gas prices declined from their mid-2008 level.

Estimates of the mean technically recoverable resource of natural gas— that is, resources that are technically producible using currently available technologies and industry practices— have also been increasing. EIA's Annual Energy Outlook 2011 uses a total resource estimate for U.S. natural gas (onshore and offshore, including Alaska) of 2,543 Tcf, including 862 Tcf of shale gas, (35 Tcf of proved reserves plus 827 Tcf of technically recoverable unproved resources.) (*Figure 1).

The U.S. natural gas outlook

EIA projects and analyzes U.S. energy supply, demand, and prices through 2035 in our Annual Energy Outlook. EIA sees a continuing rise in both natural gas production and consumption as the probable future trend.

Some factors that supported recent production growth, however, are expected to play less of a role in the immediate future. These include hedging strategies that cushioned the impact of the decline in natural gas prices since mid-2008; and lease terms (signed when prices were high) that required drilling to begin within a fixed time period in order for lease rights to be retained. However, other drivers are starting to play a larger role in boosting production activity. For example, international joint venture partners, who appear to place a value on gaining technical experience and technology associated with shale drilling in addition to the value of production, have provided major infusions of cash to North American companies. Another driver that continues to boost production is the focus on areas where highly valued crude oil and natural gas liquids are being produced in conjunction with shale gas.

Production Growth to 2035—In EIA's Reference case projection, which assumes no changes in public policy, total natural gas production grows by 26 percent, from 21.0 to 26.3 Tcf, between 2009 and 2035, due primarily to significant increases in shale gas production, which comprises about 47 percent of U.S. dry gas production by 2035. Production increases faster than demand resulting in net imports declining to below five percent of consumption by 2023 (Figure 2) (Figure 3).

Price Projections to 2035—In EIA's Reference case projections, natural gas production costs and prices are expected to rise over time as production shifts away from the most attractive "sweet spots" to less productive areas. Average annual wholesale natural gas prices remain under $5 per million Btu (all prices are in real 2009 dollars) through about 2020, increasing to higher levels thereafter. As the shale gas resource base is developed, production gradually shifts to resources that are somewhat less productive and more expensive to produce. At the same time,

* All figures have been retained in committee files.

more shale wells are drilled to meet growth in natural gas demand and offset declines from other sources, increasing demands on the drilling sector and raising costs over time.

With respect to prices, we have already noted that the energy-equivalent price premium for oil relative to natural gas has grown dramatically in recent years. Oil prices, which were typically 1 to 1.5 times higher than natural gas prices on an energy equivalent basis during the 1995 to 2005 period, are now over 3 times higher than natural gas prices. In EIA's AEO 2011 Reference case projection, the ratio of oil-to-natural gas prices remains above 3 on an annual average basis, as the balance of gas supply and demand within North America limits natural gas price increases at a time when the world supply-demand balance for oil is expected to push oil prices up at a faster rate (Figure 4).

Shale Gas Uncertainties—EIA fully recognizes the uncertainties surrounding our Reference case natural gas projections. In fact, we actively highlight them. AEO2011 includes a special section that examines some of the key uncertainties surrounding shale gas and presents the impact of higher and lower shale gas resource and cost assumptions for production, consumption, and prices. Several factors could lead resources and production to be lower or higher than what EIA includes in its Reference case. Some examples include: 1) As most shale gas wells are only a few years old their long-term productivity is untested, 2) Gas production has been confined largely to "sweet spots" that may not provide suitable data to infer the productive potential of an entire formation, 3) Many shale formations (particularly, the Marcellus shale) are so large or new that only a portion of the formation has been production tested, 4) Technical advances can lead to more productive and less costly well drilling and completion.

The Shale Gas cases in AEO2011 illustrate how a wide variation in outlooks can occur due to the underlying uncertainty regarding this emerging resource. Two key determinants of the estimated technically recoverable shale gas resource base are the estimated ultimate recovery (EUR) per well and the recovery factor that is used to estimate how much of the acreage of shale gas plays contains recoverable natural gas. The largest variations occur in the High- and Low Shale EUR cases, where lower and higher costs per unit of shale gas production have the effect of increasing and decreasing projected total production from U.S. shale gas wells. In the Low Shale EUR case, the Henry Hub natural gas price in 2035 is 31 percent higher than the AEO2011 Reference case price of $7.07 per million Btu (2009 dollars). Conversely, in the High Shale EUR case, the Henry Hub price in 2035 is 24 percent lower than in the AEO2011 Reference case. Shale gas production is more than three times as high in the High Shale EUR case as in the Low Shale EUR case, at 17.1 Tcf and 5.5 Tcf, respectively, as compared with 12.2 Tcf in the AEO2011 Reference case (Figure 5).

Demand outlook to 2035—Demand for natural gas in the Reference case grows by over 16 percent between 2009 and 2035 (Figure 6). Consumption growth is driven by the industrial and electric generation sectors. Natural gas use in the industrial sector grows by 25 percent from 2009 to 2035, reflecting the recovery in industrial output and relatively low natural gas prices, which spurs a large increase in natural gas consumption for combined heat and power (CHP) generation more than offsetting the decline in natural gas use for feedstock. Electric generation also shows strong growth in natural gas use, where 65 percent of capacity additions between 2010 and 2035 are expected to be natural gas fired. In addition to capital cost considerations, uncertainty about future limits on greenhouse gas emissions and other possible environmental regulations reduce the competitiveness of coal-fired plants.

There are also significant uncertainties affecting the demand side of the natural gas market which EIA has examined in various previous editions of the Annual Energy Outlook. Some uncertainties relate to the impact of possible future policies, others to future developments in the North American and global markets for natural gas.

For example, several factors, including regulatory changes, could increase the use of natural gas in the electric power sector. AEO 2011 includes several cases that look at the sensitivity of the generation mix and coal retirements to different assumptions regarding the price of natural gas, the extent and cost of environmental control retrofits required for existing coal-fired facilities and the recovery period for retrofit investments. A scenario that combines significant retrofit requirements, a rapid payback of retrofit costs, and continued low natural gas prices results in significant near-term retirements of existing coal plants and more use of natural gas for generation.

A second demand uncertainty involves increased use of natural gas as a transportation fuel. In the 2010 edition of the Annual Energy Outlook, EIA included sensitivity cases that explored the impact of significant incentives to promote the use of natural gas as a fuel for heavy duty trucks.

Another significant demand uncertainty involves the potential that the North American market for natural gas could become more fully integrated into the global market for natural gas. The degree of integration will depend on the extent of natural gas trade between North America and the rest of the world in the form of liquefied natural gas (LNG). The pricing regime in global LNG markets is another uncertainty, particularly the extent to which world LNG prices reflect “gas on gas” competition versus retaining the traditional linkage of LNG prices to oil prices. Shale gas resources in the rest of the world, which EIA has been closely following, and their potential development are among the key factors that will shape the development of global markets for natural gas (Figure 7).

This concludes my statement, Mr. Chairman, and I will be happy to answer any questions you and the other Members may have.

The CHAIRMAN. Thank you very much.

Dr. Moniz, go right ahead.

STATEMENT OF ERNEST J. MONIZ, CECIL AND IDA GREEN PROFESSOR OF PHYSICS AND ENGINEERING SYSTEMS DIRECTOR, MIT ENERGY INITIATIVE, MASSACHUSETTS INSTITUTE OF TECHNOLOGY, CAMBRIDGE, MA

Mr. MONIZ. Thank you, Mr. Chairman, Ranking Member Murkowski and distinguished members of the committee. We appreciate the opportunity to present results of our recent study on natural gas. I'm honored to appear before this committee once again.

I should say the study was carried out by a multidisciplinary group of 19 faculty and senior researchers over a 3-year period together with 10 graduate students, who do most of the work, and some additional contributing authors. For context, this is the fourth in our series of studies on various pathways to our energy future with a particular emphasis on a low carbon future. Nuclear, nuclear fuel cycles, coal, soon the grid and solar energy within the next several months.

When we started this study we had an open mind whether natural gas, the least carbon intensive fossil fuel, is part of the problem or part of the solution in a carbon context. Our top line conclusion is that based on the availability of large amounts of moderately priced natural gas that can indeed provide a critical bridge to a low carbon future. But assuming progressively more stringent carbon constraints down the road in some decades, natural gas itself, becomes too carbon intensive. We need a very low carbon landing point for this bridge to the future, emphasizing the need for continuing innovation on zero carbon options, renewables, nuclear, carbon capture and sequestration, even as we exploit the robust domestic natural gas resource. I would emphasize that in fact a critical issue for both coal and natural gas in a long term carbon constrained future is reducing the cost of carbon capture very, very dramatically.

I'll briefly summarize some of the key conclusions.

On the supply side, the world indeed, has a lot of inexpensive natural gas, most probably around 9,000 trillion cubic feet at costs below $4 a million Btu. A lot of it is stranded up to now, but long pipelines and LNG trade are changing that.

Domestically, we largely agree with the EIA estimates, although we are somewhat less bullish in our numbers. We estimate around 900 trillion cubic feet recoverable gas in the modest price range of

$4 to $8, more than half of that shale gas. But also noting considerable uncertainty and substantial intra and inter play variability.

We should emphasize the economics are complex because of large, well to well variability and dependence on liquid content. For example, a moderately wet well with today's oil price, can easily have a natural gas breakeven price, half of that without the liquids. So it's a very complex economic play. But the reality is the proof is in the pudding. As Howard said, shale gas is growing very dramatically in its contribution to our energy supply.

These supply curves, availability at various costs, are then inputs to our modeling. Before I describe those results, a few words on the environmental issues, these are clearly very important.

Key issues.

The need for the highest standards of well completion systematically implemented and regulated. We recommend complete transparency with respect to frack fluids.

Management of surface waters, absolutely critical. We recommend mandatory integrated, I emphasize, regional water use and disposal plans.

Mitigation of industrial activity. For example, by maximum water recycling.

We also recommend a joint DOE/EPA in depth study on the question of methane emissions in the production and delivery of all fossil fuels.

All in all our conclusion is very much along the lines that you said in opening the hearing, we consider these environmental issues quite challenging. But also manageable in the sense that we know how to address them, but we have to execute in a proper way. That's in some contrast to what I would consider the more difficult challenge of managing CO_2 emissions in combustion of fossil fuels.

We find increased gas use under just about any scenario. Any relatively more important role over the next decades at least in a carbon constrained scenario. One uncertainty is the evolution of the global natural gas market.

Today we have a fragmented regional market with 3 larger markets. If an integrated natural gas market develops, globally, and that's a big if, I'm not quite sure how we get there. But if we do get there, what we find is that it has substantial impact on the United States, lower prices, but also the potential for substantial imports in 20 to 30 years.

So this is a complex issue. Nevertheless, for economic and geopolitical reasons, we recommend support for the development of global market. That would entail for example, erecting no barriers to either the export or import of LNG.

With this supply picture we look at substitution possibilities. Natural gas for coal in electricity and industry. Natural gas for electricity in buildings. Natural gas for oil in transportation.

Some results.

First, if we chose tomorrow to substitute underutilized, existing natural gas combined cycle capacity for coal plants, especially old, inefficient plants. About a third of our fleet is over 40 years old, relatively small and without emission constraints. We could reduce CO_2 emissions in the power sector by 20 percent. We will reduce mercury and nox emissions by about a third. We would increase gas use by about 4 trillion cubic feet per year. This would be at a cost of about $16, 1, $6, per ton of CO_2. So that is something that is there in terms of not requiring capital investment and having a major shift. As an aside, the mercury rule in process at the EPA, as Howard said, will certainly have a major impact on this substitution possibility.

In industry about 85 percent of natural gas use is for heat, boilers and process heat. I will defer to Mr. Biltz to discuss the feed stock issues. Although I would note that Dow was very helpful in our developing the data in that area.

But on the issue of heat there's, of course, another EPA rulemaking in process. That is for industrial boiler emissions. Again, heat is a huge use for natural gas industry. We find a very attractive net present value for meeting control requirements of mercury and other hazardous air pollutants by fuel switching to commercially available, super efficient, like 94 percent, natural gas boilers rather than retrofit of large coal boilers. We recommend the EPA include this in their revised proposed rule.

For buildings we support the National Research Council recommendation to move to source that is life cycle emission standards rather than site standards. This has the potential for substantial emissions reductions. However, we also emphasize that such standards are not simple to implement. They will differ by regional climate conditions. They will differ by regional electricity mix. But I think the DOE should really move to see how can we incorporate these regional variations into good, life cycle emissions standards.

For transportation. The oil gas price, as we've heard, is historically high today. This provides an impetus to look at possible substitution for oil in transportation, but direct use of natural gas whether CNG or LNG does face a substantial cost premium for the vehicles.

CNG certainly makes sense already for high mileage fleets as we see. We find in our modeling significant penetration of light duty vehicle CNG vehicles in several decades when there is a large CO_2 price in addition in our model.

LNG for heavy trucks we find is very challenged by high capital costs, the order of $70,000 per vehicle, fueling infrastructure, resale value of class A vehicles on the international market and the like. This frankly does not look attractive to us for general use. Although, it may find a role in high mileage, station to station use.

Finally in this context, gas to liquids certainly not for CO_2 reduction but for oil displacement. There are many pathways. One large commodity produced today is methanol. It has challenges similar to ethanol in terms of vehicle modification and infrastructure. But for energy security the most important step that we could take is to enable consumer arbitrage among fuels derived from different feed stocks, oil, biomass, natural gas, possibly coal with carbon capture and sequestration.

So that's gasoline, ethanol, methanol. That leads us to consider flex fuel vehicles. There are some challenges but we would recommend that that be given a very, very hard look to provide this arbitrage from different feed stocks.

In coming to a conclusion I'll just mention on intermittency. We look at the implications of large scale intermittent deployed renewables, especially wind. Bottom line what we would say is we have to look at the complementarity of such intermittent renewables in gas getting in a much more systematic way for reliability of our system. Also we need to address regulatory issues like a much more robust capacity market if we are, in fact, to realize this future.

Finally R and D. I'll note that public and public/private funding of natural gas R and D is way down from its peak. Rather ironic given the increasing role of natural gas in our energy discussion. So we do recommend a revitalized program both at DOE weighted toward basic research and through a public/private partnership industry led, weighted toward applied research and demonstration.

Thank you again for the opportunity to testify. I look forward to your questions and comments.

[The prepared statement of Mr. Moniz follows:]

PREOARED STATEMENT OF ERNEST J. MONIZ, CECIL AND IDA GREEN PROFESSOR OF PHYSICS AND ENGINEERING SYSTEMS DIRECTOR, MIT ENERGY INITIATIVE, CAMBRIDGE, MA

Chairman Bingaman, Senator Murkowski, and Members of the Committee, thank you for the opportunity to present some of the key results of the recently published MIT multi-disciplinary study, The Future of Natural Gas. The study looks at:

- the economics and uncertainty of supply;
- the role of natural gas in the overall energy system, especially in the context of constraints on greenhouse gas emissions;
- the opportunities for capitalizing on an abundant natural gas supply in the electricity, industry, buildings and transportation sectors;
- infrastructure needs;
- global markets and geopolitical implications; and
- the needs for natural gas-related research and development.

The Future of Natural Gas study is the fourth in a series that presents the results of an integrated technically-grounded analysis, carried out by a multi-disciplinary group of MIT faculty, senior researchers and students, aimed at elucidating the steps needed to provide marketplace options for a clean energy future. The first three studies addressed nuclear power, coal and the nuclear fuel cycle; studies of the grid and of solar energy are in progress. We feel that the earlier studies have contributed constructively to the energy technology and policy debate in the U.S. and hope that the natural gas study will as well. In that context, we are very appreciative of the opportunity to present today.

Prior to carrying out our analysis, we had an open mind as to whether natural gas would indeed be a "bridge" to a low-carbon future. While it is the least carbon-intensive fossil fuel, it does emit greenhouse gases in combustion and potentially in production and distribution. In broad terms, we find that, given the large amounts of natural gas available in the U.S. at moderate cost (enabled to a large degree by the shale gas resource), natural gas can indeed play an important role over the next couple of decades (together with demand management) in economically advancing a clean energy system. However, with increasingly stringent carbon dioxide emissions reductions, natural gas would eventually become too carbon intensive, which highlights the importance of a robust innovation program for zero-carbon options.

We all recognize that today there is controversy about natural gas and its availability and affordability and about environmental impacts from its production and distribution. Our study addresses these issues and I hope that our analysis will inform your judgments and policy choices about the role natural gas will play in our nation's energy future.

Global Gas Resources—Scale and Cost

Global natural gas resources are abundant. Recent analysis carried out as part of the MIT Future of Natural Gas Study[1] established a mean estimate of 16,200 Tcf[2] for the remaining global resource base, with a range between 12,400 Tcf (with a 90% probability of being exceeded) and 20,800 Tcf (with a 10% probability of being exceeded). To put these estimates into context, 2009 global gas consumption amounted to 109 Tcf. These estimates do not include any unconventional resources outside of the United States and Canada, because of the large uncertainty. However, a recent EIA study has estimated a further 5,300 Tcf of shale gas internationally, just in regions that do not have large conventional resources.

Although the global gas resource base is large, it is geographically concentrated. Excluding the recent estimates of global shale resources, around which very high levels of uncertainty still exist, about 70% of all gas resources are located in only three regions: Russia, the Middle East (primarily Qatar and Iran) and North America. By some measures, this makes global gas resources even more geographically concentrated than oil. It also means that political considerations and individual country depletion policies play at least as big a role in global gas resource development as geology and economics.

*Figure 1 depicts global natural gas supply curves calculated estimated by the MIT study group. These curves quantify the price required at the point of export to enable the economic development of a given volume of gas[3]. Studying the figure indicates that much of the global gas resource can be developed at relatively low prices at the point of export. For example the figure shows that globally, over 4,000 Tcf of gas can be developed at or below $2.00/MMBtu, with 9,000 Tcf available at or below $4.00/MMBtu. These certainly are very large volumes of low-cost gas. However, a very large portion of this gas is geographically isolated from the major gas consuming markets in Europe, East Asia and North America. Unlike oil, the cost of transporting gas over long distances is high. Getting the gas to market requires either long-haul pipelines or liquefied natural gas (LNG) infrastructure. This means that gas, which can be economically developed at the export point for $1.00-2.00/MMBtu may well require an added $3.00-5.00/MMBtu of transport costs to get the gas to its ultimate destination. These high transportation costs are also a significant factor in the evolution of the global gas market.

The substantial growth in production from 1990 to 2009 is leading to the expansion of gas markets and the rise in global cross-border gas trade. From 1993 to 2008, global cross-border gas trade almost doubled, growing from 18 Tcf (25% of global supply), to 35 Tcf (32% of global supply). The vast majority of cross-boarder gas movements have historically been via pipeline. However, LNG is playing an increasing role. In 1993, 17% of cross-boarder gas trade was via LNG. By 2008 the proportion had increased to 23%, and the absolute volume had increased by 5 Tcf, or 166%. Due to improving technology and growing global gas demand, LNG is likely to continue to grow in importance.

United States Natural Gas Supply—A New Paradigm

Over the past five years the natural gas supply landscape in the United States has changed greatly—the driving force behind this change has been the rapid growth in production from shale gas plays, as illustrated in Figure 4(a). Reviewing EIA, state and commercial data reveals that the proportion of total U.S. gas production coming from shale resources grew from less than 1% in 2000, to 20% in 2010. By the end of 2011, this is expected to reach 25%. Such growth rates would be remarkable in any context, but in the U.S., the world's largest gas producing nation, it really does represent a paradigm shift.

U.S. Shale Gas Resource—Uncertainty and Relative Economics

The rapidly increasing estimates of the size of the U.S. shale resource have generated significant excitement, both within the gas industry and indeed further afield. However, shale gas production is still a nascent industry—estimates of the size and relative economics of the shale resource are still subject to considerable un-

[1] http://web.mit.edu/mitei/research/studies/natural-gas-2011.shtml

[2] In the US, natural gas volumes are typically measured in Standard Cubic Feet (Scf), where the volume is measured at a temperature of 60 F and a pressure of one atmosphere (14.7 pounds per square inch). 1 trillion cubic feet (Tcf) = 10^{12} Scf. Outside North America, natural gas volumes are typically measured in cubic meters. 1 cubic meter 8[35.3 cubic feet.

* All figures have been retained in committee files.

[3] Supply curves shown here are based on oil field costs in 2007. There has been considerable oil field cost inflation, and some recent deflation, in the last 10 years. We have estimated cost curves on a 2004 base (the end of a long period of stable costs) and a 2007 base (reasonably comparable to today's costs, 70% higher than the 2004 level, and continuing to decline).

certainty. Supply-side analysis carried out as part of the MIT Future of Natural Gas Study has explored this uncertainty in great detail, both at the resource size and relative economics levels. Some of the key conclusions of this analysis include:

1. Shale gas is now a very substantial component of the overall U.S. gas resource base—MIT's mean estimate of recoverable shale gas volumes is 630 Tcf, or just over 30% of all U.S. gas resources.
2. Significant uncertainty exists regarding the size of the shale resource—MIT's low estimate (90% probability of being exceeded) is 418 Tcf, and its high estimate (10% probability of being exceeded) is 871 Tcf.
3. Shale gas is not "cheap gas," rather it is a large resource of "moderate cost gas," with a less steep supply curve than other resource types—Of the 900 Tcf of gas recoverable in the U.S. at or below $8.00/MMBtu, 470 Tcf is shale gas.
4. There is substantial intra and inter-play variability in the production, and associated economic performance of individual shale wells; however, on a portfolio basis the shale plays are high performance.
5. The fact that many shale plays also produce natural gas liquids, whose price is linked with the oil price means that the economics of shale can be substantially better than they would appear if only gas production is considered.

The impact of shale gas on the scale and relative economics of the U.S. gas resource base is shown in Figure 5(a) & (b). Figure 5(a), illustrates the mean, high and low U.S. natural gas supply curves calculated for the MIT Future of Natural Gas Study. Figure 5(b) disaggregates the mean supply curve from Figure 5(a) by gas type. Reviewing Figure 5(b) reveals that relatively small volumes of gas are available at or below $4.00/MMBtu. This reflects the maturity of the U.S. resource base, which has seen much of its "easy" gas produced over the past decades. However, of the gas available in the moderate price range; $4.00-8.00/MMBtu, over 60% is shale. For the coming two decades MIT analysis predicts U.S. gas prices in the $6.00-8.00/MMBtu range. At these price levels Figure 5(b) illustrates that shale gas will in most instances be the lowest cost resource. An important point to keep in mind when considering gas prices is the fact that 2011 U.S. prices have been very low, due in all likelihood to a combination of macro-economics factors, and an over-supply of gas from prolific shales, where operators continue to drill in the short-term in order to hold lease positions. In the recent past U.S. prices have been substantially higher than $10.00/MMBtu, and in this context the shale resource appears very attractive.

An illustration of this variability is shown in Figure 6(a), which plots the probability distribution of the initial production rates (IP) (a key performance metric of shale wells) of the wells drilled in Texas' Barnett Shale play during 2009. This distribution is made up of over 1,600 individual wells. Reviewing the data reveals there is a 3X variation between the IP rate of a good (P20), and bad (P80) well. Such a wide range would be uncommon with conventional gas; however, similar variability is observed in all the major shale plays currently in production. Naturally, this variability impacts on the economics of shale wells. Figure 6(b) shows a table that illustrates how the performance variation of shale wells drilled during 2009 in the five major gas shale plays translated into per-well breakeven gas prices (BEPs).

For the plays shown in Figure 6(b), the BEPs for P50 wells, i.e. median performance wells, range between $4.00 and $6.50/MMBtu. However, many of the wells in each play had much higher and lower BEPs due to the wide production performance variation. This means shale gas producers are not currently drilling only low-cost shale resource; rather their drilling is sampling along the entire supply curve. Clearly this is not ideal, as operators would rather only develop the lowest-cost resources; however, as long as their overall portfolio BEP is acceptable, the variability in individual well performance is of little concern. That is not to suggest that operators are not interested in reducing this variability. Significant work is ongoing to reduce the per-well performance variability through the use of better technology.

Along with gas production variability, the economics of shale can be significantly influenced by the co-production of natural gas liquids (NGLs), whose price is linked to the international price for oil. Some shale areas are termed "wet," meaning that wells in those areas produce NGLs along with gas, and depending on the ratio of liquid to gas production, the L/G ratio, the BEPs of shale wells in such areas are often dramatically lower than they would be if the wells only produced gas. A demonstration of how significant an impact NGLs can have on shale well economics is shown in Figure 7. Here, the BEP calculated for a theoretical well assuming a 2009 Marcellus P50 gas production rate is plotted as the L/G ratio is varied from 0 to 50.

In this theoretical example, the BEP drops from $4.00/MMBtu, to $0.00/MMBtu as the L/G ratio rises from 0 (a "dry" well) to 50 (a very wet well). With appreciable

NGLs production, the gas effectively becomes free. Several of the major shale plays currently in development contain zones which are "wet," including the southwest portion of the Marcellus shale in Pennsylvania and the Eagle Ford shale in southwest Texas. In these areas, shale wells which may not appear economic at first glance based on the cost of drilling and the price of gas alone, are in fact likely to be making money due to the favorable oil-gas price spread.

Shale Gas Development—Environmental Concerns and Impacts

The growth in shale gas production has not been without controversy. The use of hydraulic fracturing (or fracking as it is referred to in the oil field vernacular), a necessary step in shale gas extraction, has been a particular focus of scrutiny by groups concerned about the environmental impacts of shale gas production. The MIT Future of Natural Gas Study examined the environmental issues around shale gas production and identified a set of primary environmental risks, which arise from shale development. They are:

- Contamination of groundwater aquifers with drilling fluids or natural gas while drilling and setting casing through the shallow freshwater zones;
- On-site surface spills of drilling fluids, fracture fluids and wastewater from fracture flowbacks;
- Contamination as a result of inappropriate off-site wastewater disposal;
- Excessive water withdrawals for use in high volume fracturing; and
- Excessive road traffic and impact on air quality

In considering these risks, the MIT analysis concluded that they are "challenging but manageable." In all instances the risks can be mitigated to acceptable levels through appropriate regulation and oversight. In particular, the risk of groundwater contamination via gas migration or from drilling fluid can be effectively dealt with if best practice case setting and cementing protocols are rigorously enforced. Regulation of shale (and other oil and gas) activity is generally controlled at the state level, meaning that acceptable practices can vary between shale plays. The MIT study recommends that in order to minimize environmental impacts, current best practice regulation and oversight should be applied uniformly to all shales. It is also the case that shale gas production can result in a large industrial activity. The local communities clearly have a strong role in evaluating the tradeoffs of significant economic activity and industrial activity.

On the specific concerns that surround the chemicals being used in fracture fluids, The MIT study recommends requiring complete public disclosure of all fracture fluid components. Furthermore the study recommends that efforts to eliminate the need for toxic components in fracture fluid be continued. The study also recommends required integrated regional surface water management plans.

Another concern has been that of methane emission during natural gas production, delivery and use. These factors have been included in the modeling described in the next section. Nevertheless, we recommend that the DOE and EPA should co-lead a new effort to review, and update as appropriate, the methane emission factors associated with fossil fuel production, transportation, storage, distribution, and end-use. This has public policy implications. The review and analysis should rely on data to the extent possible.

The Role of Natural Gas in a Carbon-Constrained World

To examine and analyze the role of natural gas in a carbon-constrained world, we utilized MIT's EPPA model, a global model which has been used and refined over twenty years to examine the complicated interplay of economics, a range of energy technologies, and trade flows for 16 regions in the world, including the US. The model accounts for all Kyoto gases. The study's supply/cost curves, discussed above, were inputs to the economic modeling work and the results, while based on global analysis, are focused on the US. I also stress that the results are not "predictions" but are instead scenarios based on assumptions and economically driven behavior.

We focus today on the CO_2 price scenario in the study which assumes the following: a 50% reduction from 2005 to 2050 in CO_2 emissions by developed nations, with no offsets; a 50% reduction in CO_2 emissions by large emerging economies by 2070; and no emissions reductions from least developed nations

There are several key takeaways from this analysis, two of which are clearly seen in Figure 8. This graph is a result of EPPA runs and depicts the US power sector only under the scenario described above, carried out to 2100. In this graph, which reflects a model driven by ruthless economics in the face of the stringent CO_2 limit, we find:

- there must be significant demand reduction from business-as-usual to meet the emissions reduction targets;

- natural gas consumption increases dramatically. This occurs because of the lower carbon characteristics of natural gas;
- there is total displacement of coal generation largely with natural gas generation by around 2035;
- carbon capture and sequestration (CCS) is too expensive to make inroads for many decades; and
- by around 2045, natural gas itself becomes too carbon intensive to meet the carbon limits and consumption starts to decline. The slack in this pre-Fukushima model run is taken up largely by nuclear but this could be any scalable no-carbon generation fuel; the point is decarbonization of the power sector after mid-century.

This figure has become known in our group as the "bridge fuel" slide. It graphically illustrates the essential role natural gas plays between now and 2050 in a carbon constrained world by substituting for coal generation in the power sector. It also makes the point that the bridge must have a suitable landing point. We must continue to invest in research in carbon-free sources—renewables, nuclear, and CCS for both coal and natural gas.

The global market structure is important for the results because of trade between different regions. Currently there is no global market in gas that approximates the oil market. Instead, we have three distinct regional markets where gas prices are established in different ways and trade between the three is relatively restricted. We used the model to explore a scenario in which the regional barriers to trade are lifted, leading to a truly global market in gas (of course with transportation costs included). The results are seen in Figures 9a and 9b.

Interestingly, in spite of the substantial domestic gas supply in the US, by 2030 we see an increase in gas imports to the US. This occurs because, as I have noted, there are abundant supplies of very low-cost gas in the world, and the LNG transportation costs can be overcome for some gas.

This may understandably raise concerns about energy security and reliance on imports. This scenario demonstrates however that there are major benefits to US gas consumers as prices for gas are substantially lower (almost 25%) in the global market scenario. Also, domestic gas production does not decline in the US for quite some time despite the imports. This is because the lower gas prices in the global market scenario increase demand and imports largely make up the increased demand.

Fuel Substitution Options

The U.S. natural gas supply situation has created new opportunities for expanding natural gas use, enhancing the substitution possibilities for natural gas in the electricity, industry, buildings, and transportation sectors. I will specifically discuss the substitution of gas for:

- coal in the power generation sector;
- coal in the industrial sector, specifically for industrial boilers;
- electricity in buildings; and
- oil in transportation.

I will also briefly highlight the impacts on natural gas of large scale penetration of intermittent renewables in the power sector.

Natural Gas Substitution for Coal in the Power Sector.

As noted in the EPPA discussion above, under a carbon-price scenario natural gas displaces coal in the power sector by around 2035. In the gas study, we drilled down in this area to try to understand how this substitution might occur and what some of the impacts might be. More specifically, we examined opportunities created by the current surplus of natural gas combined cycle generation capacity and what the impacts of utilizing this "surplus" capacity might be on carbon emissions.

The US has more installed nameplate natural gas generation capacity than coal (see Figure 10) but gas supplies only 23% of our generation compared to 44% from coal; this demonstrates that there is significant unused gas capacity. NGCC generation units in the U.S. averaged only 42% capacity factors in 2009 (*Table 1) although they are capable of operating at capacity factors of around 85%. NGCC units are highly efficient, relatively inexpensive to build, and produce significantly fewer CO_2 and other pollutant emissions than coal plants.

Natural gas plants however typically have the highest marginal cost (although this is changing) and tends to get dispatched after other fuel sources for power gen-

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*All tables have been retained in committee files.

eration. This is because the marginal cost is dominated by fuel cost. We analyzed what the carbon impacts might be if we changed this order and dispatched surplus NGCC generation ahead of coal. Older inefficient coal units are good candidates for substitution by NGCC.

After isolating how much of this NGCC generation capacity is actually surplus—defined as the amount of NGCC generation that can be used over the course of one year to replace coal while respecting transmission limits, operation constraints and demand levels at any given time—through modeling we were able to conclude the following about a policy that requires the dispatch of surplus NGCC over coal generation:

- nationwide, CO_2 emissions from power generation would be reduced by 20%
- the cost of CO_2 emissions avoidance would be around $16 per ton
- mercury emissions would be reduced by 33%
- NOX emissions would be reduce by 32%
- this would require an incremental 4 tcf of natural gas

It should be noted that these impacts vary widely by region of the country, depending on the generation mix, the level of electricity imports/exports, etc (Table 2). Also, the mercury rule in development at EPA may be a significant driver for utilizing surplus NGCC capacity when weighted against the option of retro-fitting coal plants to capture mercury. Finally we note that this option may be the only practical near-term option for large scale CO_2 emissions reductions from the power sector. Policy makers could pursue this pathway for near term large-scale reductions in CO_2 and other pollutant emissions from the power sector.

Natural Gas Substitution for Coal in the Industrial Sector.

Industrial consumers represent about 35% of US gas demand. Currently, 85% of industrial demand is in the manufacturing sector and 36% of manufacturing demand is for industrial boilers. Natural gas industrial boilers have a range of efficiencies: pre-1985 gas boilers average 65-70%; those designed to meet the 2004 standard of 77-82%; and new super boilers with efficiencies in the 94-95% range.

We focus today on large industrial boilers because of standards being developed at EPA for mercury, metals, and other hazardous emissions from industrial coal fired boilers. These National Emissions Standards for Hazardous Air Pollutants (NESHAP), issued then withdrawn by Administrator Jackson for additional comments, are based on Maximum Achievable Control Technologies (MACT). Around 68% of large industrial boilers are coal-fired. Natural gas boilers, which are much cleaner, were not covered by the proposed boiler standards, although there are cost-effective options for greater efficiency. Gas boilers were also excluded from the MACT as a remedy for covered emissions from coal plants.

The EPA economic analysis supporting the new MACT standards assumed that the three sub-categories of coal boilers would retrofit with post-combustion technologies but concluded that gas fuel was too expensive for fuel switching to be considered as an option for meeting MACT standards. The price of gas assumed in the EPA analysis was $9.58 per MMBtu in 2008; today's price is less than half that.

Using EPA's methodology but substituting current gas price suggests that EPA may wish to reconsider fuelswitching as an option for meeting MACT standards. The efficiency of natural gas super boilers combined with today's gas prices shows that the net present value cost for these super boilers is slightly lower than that for retrofitting existing coal boilers (Figure 11). Substitution of large industrial coal boilers with natural gas super-boilers would consume slightly less than one Tcf of incremental gas per year and reduce CO_2 emissions by 52,000 to 57,000 tons per year per boiler. Interestingly, because the savings are so significant, there is a negative per ton CO_2 emission avoidance price of $5.00. The study concluded that replacing coal boilers with super-efficient gas boilers could be a cost-effective alternative for complying with MACT standards.

Gas Substitution for Electricity in the Buildings Sector.

As we saw in the EPPA scenarios, reduced energy consumption is a critical component of a strategy for achieving a low carbon future. Because they represent around 40% of total energy consumed in the US, buildings, both residential and commercial, are an essential focus for reducing energy demand. This is even more critical for natural gas, where buildings represent 55% of all gas consumed, including gas fired electricity for buildings.

The study focused on a comparison of the relative efficiencies of the direct use of fuels in building thermal end uses, especially space conditioning and hot water heating. It specifically examined site efficiency of these appliances (the ratio of useful energy provided divided by the amount of retail energy consumed, either electricity or fuel) compared to full fuel cycle or "source " efficiency (accounting for all energy used to extract, refine, convert and transport the fuel as well as the efficiency of the end use appliance).

DOE has historically set standards based only on site efficiency. In 2009, the National Research Council recommended that DOE move to source efficiency standards. The analysis in the study validates the NRC recommendation. Figure 12 shows the amount of energy consumed by various furnaces when one looks only at site energy and when one looks at both site and source energy. Using this number in a site calculation, a gas furnace consumes 10% more energy than an electric furnace. When source energy is considered, an electric furnace consumes 194% more energy than a gas furnace. There are corresponding reductions in CO_2 emissions.

These numbers are compelling but such standards are complicated to establish because of regional climate and regional electricity supply mix. The study recommends incorporating efficiency metrics to provide full fuel cycle comparisons in dual fueled appliance standard setting but it also finds that there is a need to inform consumers, developers and state and local regulators about the cost-effectiveness and suitability of various technologies relative to local conditions.

Gas Substitution for Oil based Transportation Fuels.

The study examines options for both direct use of natural gas for transportation as well as conversion of natural gas to liquid fuels.

- Compressed Natural Gas (CNG)—Globally, there are 11 million natural gas vehicles on the road, 99.9% of which are CNG vehicles. CNG is cheaper than gasoline on an energy equivalency basis but there are upfront vehicle costs that have inhibited the growth of the CNG vehicle markets. For a variety of reasons, some of which are not entirely clear, these costs—for both after-market conversion and factory produced issues— are much higher in the US than elsewhere in the world. The incremental cost for factory produced vehicles in the US for example is $7,000 compared to $3,700 in Europe. The incremental cost of after-market conversions in the US is $10,000, in Singapore it is $2,500.

The study analyzes the payback period for light duty vehicles assuming a $3K and a $10K incremental cost for 12000 miles and 35000 driven per year per year. At the lower conversion cost, vehicles with high miles traveled (typically fleets) have a short payback period, making this an attractive option for taxis for example. This is however illustrative; as noted incremental costs in the US are much higher than $3,000.

These data suggest that CNG offers a significant opportunity in U.S. heavy-duty vehicles used for short-range operation (buses, garbage trucks, delivery trucks), where payback times are around three years or less and infrastructure issues do not impede development. However, for light passenger vehicles, even at 2010 oil-natural gas price differentials, high incremental costs of CNG vehicles lead to long payback times for the average driver, so significant penetration of CNG into the passenger fleet is unlikely in the short term. Payback periods could be reduced significantly if the cost of conversion from gasoline to CNG could be reduced to the levels experienced in other parts of the world such as Europe. The study recommends that the US should consider revising its policies on CNG vehicles, including how aftermarket conversions are certified to reduce up-front costs and facilitate bi-fueled CNG-gasoline capability.

A CO_2 emissions charge also favors CNG vehicles relative to gasoline-fueled vehicles. In the carbon-constrained scenario discussed above, the economic scenario has substantial penetration ofCHG vehicles toward mid-century.

- Liquefied Natural Gas (LNG)—LNG has been considered as a transport fuel, particularly in the long-haul trucking sector. However, as a result of operational and infrastructure considerations as well as high incremental costs and an adverse impact on resale value, LNG does not appear to be an attractive option for general use. There may be an opportunity for LNG in the rapidly expanding segment of hub-to-hub trucking operations, where infrastructure and operational challenges can be overcome.
- Conversion of Gas to Liquid Fuels—The chemical conversion of natural gas to liquid fuels could provide an attractive alternative to CNG. Several pathways are possible, with different options yielding different outcomes in terms of total system CO_2 emissions and cost. Conversion of natural gas to diesel and gasoline for example—both drop-in fuels that can be used in existing infrastructure, a major plus— require more processing than other options.

The study looks more closely at the methanol liquid fuel option, largely because there is currently large scale industrial production of methanol and it is an alcohol like ethanol, with which we also have a good deal of experience. Methanol production and use has GHG emissions comparable to those of petroleum derived fuels and at today's oil and gas prices is significantly less expensive than gasoline on an energy basis. As seen in Table 3, at $4 natural gas, methanol is a dollar cheaper than gasoline on a gge basis. This analysis was done when gasoline was $2.30 (excluding taxes); the spread would be significantly greater at today's gasoline prices.

Methanol requires modest changes to engines because of its corrosive nature and an appropriate distribution infrastructure would be required. The issues are very similar to those for ethanol which has already penetrated the gasoline market at a material level. Introducing methanol, in addition to ethanol, has the energy security benefit of providing fuel options derived from petroleum, biomass, and natural gas feedstocks. To gain security benefits, arbitrage among the fuels is needed at the consumer level, which means flex-fuel vehicles would be required. This arbitrage would place downward pressure on prices, helping to reduce price spikes and volatility. The study group supports implementation of the open fuel standard.

In addition to its recommendation of support for flex fuel vehicles, the study recommends that the federal government conduct a serious comparative study of natural gas derived transportation fuels compared to petroleum and biofuels.

Natural Gas Power Generation and Intermittent Renewables.

Natural gas-fired power generation provides the major source of backup to intermittent renewable supplies in most U.S. markets. If policy support continues to increase the supply of intermittent power, then, in the absence of affordable utility-scale storage options, additional natural gas capacity will be needed to provide system reliability. In most markets, existing regulation does not provide the appropriate incentives to build incremental capacity with low load factors, and regulatory changes may be required.

In the short term—defined here to mean a circumstance where a rapid increase in renewable generation occurs without any adjustment to the rest of the system including generation technologies—increased renewable power displaces natural gas combined cycle generation, reducing demand for natural gas in the power sector. Modeling of the ERCOT system (Texas) provides a more detailed understanding of the generation impacts of doubling wind generation in the short term. These include:

- Wind generation primarily displaces generation from natural gas combined cycle turbines
- Coal plants are forced to cycle
- Natural gas peaking plants are used more

In the longer term, where the overall system has time to adjust through plant retirements and new construction, increased renewables displaces baseload generation. This could mean displacement of coal, nuclear or NGCC generation, depending on the region and policy scenario under consideration. For example, in the 50% CO_2 reduction scenario described earlier, increased renewable penetration as a result of cost reductions in renewable generation or government policy such as a renewable portfolio standard, reduces natural gas generation on a nearly one-for-one basis. Another effect: absent breakthroughs in storage technologies, gas peaking units will be needed to manage intermittency. These units however will not be utilized very often—not necessarily an attractive investment option or easily accommodated in existing regulatory and rate structures. As such, the study found that policy and regulatory measures should be developed to facilitate adequate levels of investment in gas generation capacity to ensure system reliability and efficiency.

The study notes a growing interdependency between natural gas and electricity infrastructures, not just to accommodate intermittent renewable penetration but also in a scenario where gas generation displaces coal generation. The degree to which this interdependency stresses both the gas and power infrastructures and creates conditions where the infrastructures and related contracting, legal and regulatory structures may be inadequate is not fully understood. The study recommends that a detailed analysis be conducted of these interdependencies. The current models are inadequate to fully understand the implications of these changing relationships.

Natural Gas Research and Development

There are numerous RD&D opportunities to address key objectives for natural gas supply, deliver, and use:

- improve the long term economics of resource development as an important contributor to the public good;

- reduce the environmental footprint of natural gas production, delivery and end-use;
- expand current use and create alternative applications for societal objectives, such as emissions reduction and diminished oil dependence;
- improve safety and operation of natural gas infrastructure; and
- improve the efficiency of natural gas conversion and end-use so as to use the resource most effectively.

Given the importance of natural gas in a carbon-constrained world, and these opportunities for improved utilization of the resource, an increase is in order in the level of public and public-private RD&D funding. Historically, public-private RD&D funding played an important role in the development of the unconventional natural gas resource. Indeed, the technologies needed to produce such resources have been pioneered in the United States and now account for about half of domestic production.

Figure 13 shows how the interplay of early stage DOE-supported reservoir characterization, the public- Figure 13. CoalbedMethane RD&D Spending 19 private Gas Research Institute (GRI) funding for technology development and demonstration, and a time-limited tax credit led to robust coalbed methane production. A Royalty Trust Fund (RTF) established in the 2005 Energy Policy Act, and implemented through a public-private partnership, is providing modest resources for unconventional gas technology, specifically including minimization of environmental impacts. However, the elimination of the GRI rate-payer funded program was not compensated by increased DOE appropriations or the RTF. The total public and public-private RD&D funding for natural gas research is down substantially from its peak and in addition is much more limited in scope.

In agreement with a recommendation made by the President's Council of Advisors in Science and Technology with respect to the overall Federal energy RD&D effort, we recommend that the Administration and Congress support a broad natural gas RD&D program both through a renewed DOE effort, weighted towards basic research, and a complementary industry-led public-private program, weighted towards applied RD&D. The latter should have an assured funding stream tied to energy production, delivery and use (such as the RTF).

Conclusion

Mr. Chairman, Senator Murkowski, members of the committee, let me conclude with a summary of some of the major findings of the study (the complete list can be found in the study):

- Even with uncertainty, there are abundant supplies of natural gas in the world, and many of these supplies can be developed and produced at relatively low cost. In the U.S., despite their relative maturity, natural gas resources continue to grow, and the development of low-cost and abundant unconventional natural gas resources, particularly shale gas, has a material impact on future availability and price.
- Natural gas plays a major role in most sectors of the modern economy is likely to continue to expand under almost all circumstances
- In a carbon-constrained economy, the relative importance of natural gas is likely to increase even further, as it is one of the most cost-effective means by which to maintain energy supplies while reducing CO_2 emissions. This is particularly true in the electric power sector, where, in the U.S., natural gas sets the cost benchmark against which other clean power sources must compete to remove the marginal ton of CO_2.
- In the U.S., a combination of demand reduction and displacement of coal-fired power by gas-fired generation is the lowest cost way to reduce CO_2 emissions by up to 50%. For more stringent CO_2 emissions reductions, further de-carbonization of the energy sector will be required; but natural gas provides a cost-effective bridge to such a low-carbon future.
- The current supply outlook for natural gas will contribute to greater competitiveness of U.S. manufacturing, while the use of more efficient technologies could offset increases in demand and provide cost-effective compliance with emerging environmental requirements.
- International gas trade continues to grow in scope and scale, but its economic, security and political significance is not yet adequately recognized as an important focus for U.S. energy concerns.

The CHAIRMAN. Thank you very much for your testimony.

Mr. Biltz, go right ahead.

STATEMENT OF GEORGE BILTZ, VICE PRESIDENT, ENERGY AND CLIMATE CHANGE, THE DOW CHEMICAL COMPANY, MIDLAND, MI

Mr. BILTZ. Thank you. Chairman Bingaman, Senator Murkowski, members of the committee, my name is George Biltz. I'm the Vice President of Energy and Climate Change for Dow Chemical. Thank you for the opportunity to discuss our views on the future of natural gas.

Natural gas may well be the most critical fuel that our economy has when you think about its growing use in homes and power plants, its importance as a use in fertilizers and therefore for food pricing and how critical it is to manufacturing. Dow is one of the largest users of natural gas. We use approximately 850,000 barrels of oil per day which is about as much energy as the country of Australia uses. We use this both as an energy source to fuel our operations as well as a raw material from plastics to pharmaceuticals.

More than 96% of all manufacturing goods are enabled by chemistry. Moreover, we turn every dollar of natural gas that we use into $8 worth of value for the economy. No other use of natural gas even comes close.

As an example of this, this is our new solar roofing shingle which is currently manufactured today in Michigan. The polymer in this revolutionary product started with American made natural gas. We think the future of natural gas is very bright. It will play a vital role in meeting the Nation's energy needs over the next decades and it will be critical for the growth of U.S. manufacturing.

As the MIT study concluded and we agree, there is a growing abundance of natural gas in the U.S. and elsewhere. The environmental challenges are manageable. We need to use the gas efficiently.

Our view is that we must deal with both supply and demand at the same time. The manufacturing sector and job creation will grow when natural gas prices are competitive. Conversely when natural gas prices are high and volatile, manufacturing becomes the shock absorber in the system. Exports drop. Companies move production elsewhere or they simply shut down.

As this chart shows which is based on EIA data and allowing for the accelerated retirement of coal fired power generation, as we just discussed from the MIT report, allowing for natural gas vehicles and the Administration's desire to replace 25% of oil imports. Demand in this case will far exceed reasonable projections of domestic supply. This will force American manufacturing to be the shock absorber once again driving exports, revenues and jobs offshore.

Recently, largely due to new Shell gas discoveries, natural gas prices have been stable. In a response manufacturing has grown. This trend can continue provided that we ensure that gas supplies are adequate to meet demand.

If this viewpoint sounds familiar, it is. As referenced earlier back in 2005, DOW's CEO was here, Andrew Liveris. He testified before this committee. He indicated that with high and volatile natural gas prices our industry would grow but it would grow outside the U.S.

We later announced joint ventures in the Middle East, Africa and Asia totaling over $30 billion of investments. Today, in contrast, the prospect of abundant natural gas at predictable prices has unleashed billions in new chemical industry investment back here in the United States. The result has been new jobs, more exports and improved trade balance and more tax revenue.

Dow has already invested 500 million in our U.S. Gulf Coast assets to increase our raw material flexibility. In April, we announced billions more in new investments. Other chemical companies are doing likewise. The American Chemical Council estimates that a 25% increase in natural gas liquid consumption could create 17,000 direct jobs and 400,000 indirect jobs.

This positive news was simply unthinkable but a few years ago. The question is how do we take advantage of the best opportunity in decades to fuel a renaissance in American manufacturing? We need 3 things.

First, policy to encourage natural gas production, so that supplies are able to meet growing demand. It is imperative that we strive for policies that balance supply and demand if we want to keep natural gas prices stable. We commend members of this committee for trying to bring consensus on the issue of OCS development.

Second, Congress must avoid legislating natural gas demand. As we like to say, we've seen this movie before and we don't like how it ends. The 1990 Clean Air Act led to fuel switching and massive natural gas price spikes. Six million manufacturing jobs and $30 billion in chemical exports went away. We simply can't afford to make the same mistakes again.

Third, enact a comprehensive energy policy. Sound national energy policy should increase, diversify and optimize domestic production of all forms of energy. Rather than pick winners and losers Congress and the Administration should encourage increased energy efficiency, renewables, clean coal, gas production and nuclear power. We need all of them to improve our energy security.

In conclusion, natural gas is a game changer. It can fuel a renaissance in American manufacturing. But only if we produce enough of it, use it wisely and don't repeat the mistakes of the past.

Thank you for inviting me to speak to you today. I'll welcome any of your questions.

[The prepared statement of Mr. Biltz follows:]

PREPARED STATEMENT OF GEORGE BILTZ, VICE PRESIDENT, ENERGY AND CLIMATE CHANGE, THE DOW CHEMICAL COMPANY, MIDLAND, MI

Introduction

The Dow Chemical Company appreciates the opportunity to submit these written comments to the Committee on Energy and Natural Resources.

Dow was founded in Michigan in 1897 and is one of the world's leading manufacturers of chemicals, plastics and advanced materials. We supply more than 3,300 products to customers in approximately 160 countries, connecting chemistry and innovation with the principles of sustainability to help provide everything from fresh water, food, and pharmaceuticals to insulation, paints, packaging, and personal care products. About 21,000 of Dow's 46,000 employees are in the US, and Dow helps provide health benefits to more than 34,000 retirees in the U.S.

Dow is committed to sustainability. We have improved our environmental performance (including on greenhouse gas emissions), and we are committed to do even better in the future. Our ambitious 2015 sustainability goals (http://www.dow.com/sustainability) underscore this commitment.

Dow is an energy-intensive company. We use energy, primarily naphtha, natural gas and natural gas liquids (such as ethane), as feedstock materials to make a wide array of products essential to our economy and quality of life. We also use energy to drive the chemical reactions necessary to turn our feedstocks into useful products, many of which lead to net energy savings. Dow's global hydrocarbon and energy use amounts to the oil equivalent of 850,000 barrels per day, approximately the daily energy use of Australia.

This testimony describes our views on natural gas supply and demand, and the value-add created by U.S. manufacturers who use natural gas.

Dow believes that natural gas will play a critical role in US energy policy. Because US manufacturing jobs are dependent on the US natural gas market, policies that impact natural gas will have a direct impact on jobs in the US manufacturing sector. We recommend that any natural gas policies carefully consider the need to preserve and enhance the competitiveness of U.S. manufacturers.

Natural Gas Fuels US Manufacturing

Major sectors that use natural gas include the power, manufacturing, residential, commercial, and transportation sectors.

US manufacturers provide the highest value-add of any sector. Using natural gas to make petrochemicals results in eight times the value over simply combusting it. This productivity stems from the fact that the chemical industry uses natural gas not just for fuel and power, but also as a raw material or "feedstock."

When natural gas prices are low relative to oil, US chemical manufacturers have a competitive advantage. Recent market activity underscores the favourable climate for US petrochemical industry. When the ratio of oil to gas price is above 7:1, Gulf-Coast-based petrochemicals are more competitive versus the world's other major chemical-producing regions. The current oilto- gas ratio is very favourable for US competitiveness and increases the exports of petrochemicals, plastics, and other products.

Not only do manufacturers provide the greatest value-add, they are also the most price sensitive. Those sectors in which demand is most sensitive to natural gas prices are termed "price elastic". The more elastic the demand, the more quickly a sector will change its demand for natural gas after a change in price. Inelastic demand occurs when a change in price results in little change in demand.

The industrial sector has the most elastic demand for natural gas. From 1997 to 2008, US industrial gas demand fell 22% as average annual prices rose 167%. Over the same time, demand for power rose 64% (EIA data). The loss in US manufacturing jobs was significant.Indeed, government data show that more than six (6) million jobs were lost in the US manufacturing sector since 1997, and volatile natural gas prices were a significant factor. Change in natural gas price will impact industrial sector demand before that in other sectors. For this reason, we sometimes say that US manufacturers are the "shock absorber" for the US natural gas market. The maintenance of a strong presence of price-sensitive users will help to minimize price volatility in the natural gas market. Government must exercise caution to avoid policies that grow inelastic demand to the detriment of price-sensitive users.

Both price volatility and the "average" price over time have an impact on the industrial sector. Therefore, policymakers should carefully consider the impact of proposed policies on natural gas price and the competitiveness of the US manufacturing sector.

As the figure illustrates, the potential exists for demand to outstrip supply, assuming that fuel switching from coal to gas continues to accelerate and factoring in the proposals by some to displace 25% of our oil imports with natural gas.

Unconventional Natural Gas

The recent MIT report, The Future of Natural Gas, confirms that the US has an abundant supply of natural gas, much of it available at an affordable price.

According to this report, the supply of natural gas is changing, as new production of unconventional gas compensate for declining reserves of conventional gas (e.g., five shale plays in the US could see a five-fold growth in production). New supplies are critical as demand for natural gas is growing in every sector of the economy, especially power generation.

The report also concludes that the current supply outlook will contribute to greater competitiveness of US manufacturing, and specifically describes how new sources of natural gas and natural gas liquids are changing the economic competitiveness of the chemical industry, leading to new investments (and job creation).

Dow is in general agreement with the report. For example, the report portrays an appropriate level of cautious optimism. It says: "While the pace of shale technology development has been very rapid over the past few years, there are still many scientific and technological challenges to overcome before we can be confident that this very large resource base is being developed in an optimal manner."

Dow has concerns, however, with two of the report's recommendations. While the study does not openly call for government subsidies for natural gas vehicles, it does call for the government to revise its policies related to CNG vehicles in order to lower up-front costs of such vehicles and the necessary infrastructure. The study also does not recognize another fact: Electric vehicles are three times more efficient than natural gas vehicles. In addition, the infrastructure for an overnight, low-voltage charging infrastructure already exists—our power grid—and it is cheaper to scale up.

The second disagreement relates to the development of an efficient and integrated global gas market. It states, "Greater international market liquidity would be beneficial to U.S. interests. U.S. prices for natural gas would be lower than under current regional markets, leading to more gas use in the U.S." It is hard to understand how this can be. The U.S. has very competitive natural gas prices and exposing it to the rest of the world, where prices are linked to oil price, will not lower domestic prices. In our view, a global market will raise US prices which will be bad for competitiveness of all US energy intensive industries including chemicals. If the US were to begin exporting natural gas, the world market would equilibrate to one world price (with transportation cost differences) which would bring lower prices outside the US and higher prices for US consumers.

The study also offers some acceptable recommendations but in doing so calls for unacceptable policy. One recommendation reads, "In the absence of such policy, interim energy policies should attempt to replicate as closely as possible the major consequences of a 'level playing field' approach to carbon-emission reduction. At least for the near term, that would entail facilitating energy demand reduction and displacement of some coal generation with natural gas." We would have no problem with the first part of that statement, but do not see the need for facilitating displacement of coal with natural gas. It is our belief that market and regulatory forces will naturally move it in that direction.

EIA data shows that since 2000, the vast majority of new power plants constructed use natural gas. When setting policy, it is important to note that homeowners, farmers, and the industrial sector are all dependent upon the use of natural gas, and do not have economic alternatives. At the same time, the electric power generation and transportation markets do have alternative sources of energy. Policy that increases demand for natural gas without ensuring that there is available supply can increase the price of natural gas and electricity for all home-owners, farmers and the industrial sector.

In the recommendation to "set a CO_2 price for all fuels," there is no discussion about the negative impact on energy-intensive trade exposed industries. These increased energy costs would not be absorbed by offshore competitors and thus would give them a competitive advantage, endangering U.S. jobs.

Another claim of the report is questionable: "Displacement of coal-fired power by gas-fired power over the next 25 to 30 years is the most cost-effective way of reducing CO_2 emissions in the power sector." We would argue that demand reduction via energy efficiency is at least as important in cost effectively reducing CO_2 emissions in the power sector and should preferably be pursued prior to any effort to displace coal-fired power by gas. While the study considers the impact of natural gas on the government objective of environmental protection, it also needs to consider the impact that any policies will have on the equally important objectives of economic growth and national security. The above recommendation will likely increase natural gas prices, which will reduce the competitiveness of U.S. industries.

Finally, the study noticeably lacks any recommendations for a streamlined, timely process for exploration and production permitting to ensure access to supply despite the report stating "a robust domestic market for natural gas and NGLs will improve competitiveness of manufacturing industries dependent on these inputs." In our view, it is imperative that increased demand not precede increased supply. Access to offshore natural gas and crude oil is essential for U.S. energy security. Political and regulatory uncertainty threatens to significantly reduce the amount of natural gas that can be extracted. These issues, including regulations around the use of hydraulic fracturing, must be resolved for companies to invest capital in the U.S. based on the new natural gas discoveries.

A Potential Renaissance for US Chemical Manufacturers

What does the promise of increased domestic supply of natural gas mean to US manufacturers?

We believe an increase in the natural gas resource base, especially ethane-rich gas such as that in the Marcellus and Eagle Ford regions, could be a "game changer" for US manufacturers.

The American Chemistry Council (ACC) recently evaluated the impact of a 25 percent increase in the US ethane supply from shale gas. Such an increase in ethane supply would generate

- 17,000 new jobs in the US chemical industry
- $32 billion increase in US chemical production,
- $16 billion in new capital investment in the chemical industry,
- 395,000 new jobs outside the chemical industry, including 165,000 jobs in supplier industries, and 230,000 jobs from new capital investment by the chemical industry.

This would generate an increase in US economic output of $132 billion per year, and raise $4.5 billion per year in additional annual tax revenue for federal, state, and local governments.

ACC is careful to acknowledge that a reasonable regulatory regime will facilitate shale gas development, but the wrong policy initiatives (e.g., state moratoria on shale gas development, and other policies that artificially increase demand) could derail recovery, economic expansion, and job creation.

The full ACC report is contained in the Appendix to this testimony.

Environmental Issues

Legitimate concerns have been raised about the use of hydraulic fracturing (also known as hydrofracking or fracking) to access unconventional gas reserves.

Dow believes that, if done in a safe and effective manner, hydraulic fracturing poses little threat to the environment and is essential for the production of natural gas from shale formations.

As conventional sources of natural gas in the US decline, shale gas will play a vital role in the nation's energy demand over the next decades.

Dow produces products used in association with hydraulic fracturing, such as biocides for microbial control to ensure gas can escape through the fractures. Our biocide products are registered with EPA and with each state where the material will be used. The stringent regulatory requirements are supported by detailed toxicological and environmental fate data which allows selection of proper materials for the given application and region.

In addition to biocides, Dow also produces other products used in hydraulic fracturing. Dow has committed to publishing health information for all of our products and to make this information available on our public website.

Chemicals in the hydrofracking process make up less than 1 percent of the fluids used. Federal law currently requires companies to report the hazards of components present in formulations >0.1 percent or >1 percent depending on the nature of the hazards. The law further requires that this hazard information is available to employees via Material Safety Data Sheets at all worksites.

Dow supports transparency with respect to chemical hazards as a principal component to ensure worker and environmental safety. We promote progressive chemicals management policies and best practices worldwide through voluntary standards such as Responsible Carer®. We believe that disclosure of chemical identity should be pursued to the extent possible without compromising true trade secret information, while fully characterizing the hazards of the individual components or formulated product to alleviate concerns about the risk to human health and the environment.

As this debate further develops, we will share chemicals management best practices and provide our feedback on targeted regulations in development to preserve the economical production of energy from unconventional gas resources. Domestic oil and gas production is a necessary part of a balanced energy policy.

U.S. Energy Policy and Natural Gas

Dow has developed an advanced manufacturing plan to promote a competitive manufacturing sector. The plan includes policy recommendations in eight areas, ranging from trade and education to health care and tax policy. It also calls for a comprehensive energy policy, which has four pillars: (1) aggressive pursuit of energy efficiency and conservation; (2) increasing, diversifying, and optimizing domestic hydrocarbon energy and feedstock supply; (3) accelerating development of alternative and renewable energy and feedstock sources; and (4) transitioning to a low-carbon economy.

Natural gas plays a key role in these recommendations. In particular, Dow supports policies to increase domestic production of natural gas in an environmentally responsible manner, including conventional and unconventional natural gas.

According to the Department of the Interior, there are 93 million barrels of oil and 456 trillion cubic feet of natural gas offshore on our nation's Outer Continental Shelf (OCS). These are domestic supplies that can be produced with state-of-the-art techniques that ensure environmentally responsible production, while greatly enhancing our nation's energy and feedstock security. Dow has consistently and persistently supported expanded access to OCS resources.

One way to maximize the transformational value of increased oil and gas production in the OCS is to share the royalty revenue with coastal states and use the federal share to help fund research, development and deployment in such areas as energy efficiency and renewable energy. Production of oil and gas on federal lands has brought billions of dollars of revenue into state and federal treasuries. Expanding access could put billions of additional dollars into state and federal budgets.

Dow also believes natural gas can play a role in transitioning to a low-carbon economy. In a much-cited study, Princeton scientists Socolow and Pacala identified 14 specific solutions, each with the potential to reduce one (1) gigaton of carbon dioxide. One of these solutions was fuel switching from coal to natural gas in the generation of electricity. Such fuel switching has been an ongoing trend in recent years, due in part to a downward trend in the price of natural gas. For several reasons, this trend is likely to continue, especially as pressure builds to retire the oldest coal-fired power plants. However, great caution must be taken if the government advances policies to make this transition more abrupt.

Natural gas—including unconventional gas—is a critical component of a balanced US energy policy. The key is to ensure alignment between supply and demand, and to avoid shocks to the market from unwise government policy. The remainder of this section addresses some of these important policy issues: inclusion of natural gas through imposition of a federal Clean Energy Standard (CES), EPA regulations affecting coal-fired power, and tax incentives for natural gas vehicles. Each poses a challenge to US manufacturing.

Clean Energy Standard (CES)

In his last State of the Union address, the President has called for "efficient natural gas" to be included in the mix of clean energy technologies that would receive credit under a clean energy standard (CES). We recommend a significant and critical review of such a proposal.

Dow remains concerned about the potential for natural gas volatility that is damaging to the manufacturing sector. At a time when there continues to be debate about access to domestic natural gas supplies, Congress and the Administration must exercise extreme caution in pursing policies that encourage fuel switching from coal to natural gas in the power sector, which is already happening in the absence of government incentives. In this regard, we note that the Bipartisan Policy Center, in a landmark study of natural gas volatility, has made the same recommendation:

> Government policy at the federal, state and municipal level should encourage and facilitate the development of domestic natural gas resources, subject to appropriate environmental safeguards. Balanced fiscal and regulatory policies will enable an increased supply of natural gas to be brought to market at more stable prices. Conversely, policies that discourage the development of domestic natural gas resources, that discourage demand, or that drive or mandate inelastic demand will disrupt the supplydemand balance, with adverse effects on the stability of natural gas prices and investment decisions by energy-intensive manufacturers.

EPA Regulations Affecting Coal-Fired Power

The government-imposed shocks we worry about most relate to fuel switching: (1) from coal to natural gas in the power sector due to EPA regulation and (2) from gasoline to natural gas in the transportation sector due to government incentives for natural gas vehicles.

EPA is developing several major regulations (e.g., the recently finalized "transport" rule and the proposed utility MACT) that will increase the cost of operating coal-fired power plants, thus providing an added incentive for the retirement of such plants and the construction of replacement generation capacity. This replacement generation is likely to come from natural gas. Dow believes it would be most prudent to ensure a reasonable transition time for the retirement of the oldest coal-fired power plants. The more uncertain the regulatory environment, the more likely the transition will be abrupt, which could alter the demand-supply balance so critical to US manufacturers.

Incentives for Natural Gas Vehicles

Congress is contemplating tax incentives for natural gas vehicles. The goal, as noted by proponent T. Boone Pickens, is to replace 25% of our oil-based transportation fuel with domestically produced natural gas.

Dow and the chemical industry are opposed to such incentives because of the upward pressure they will impose on natural gas demand. Data from the Energy Information Agency suggests such a move, in combination with expected fuel switching in the power sector, will most certainly lead to a situation where demand will outpace supply, with a detrimental effect on US manufacturing. History suggests that such supply-demand imbalances result in demand destruction for US manufacturers.

This latest push to promote natural gas vehicles raises legitimate questions about the incoherent signals that policymakers are sending to the transportation sector. Daniel Yergin recently described the situation. “Could natural gas also be a game changer for transportation? That is much more of a challenge. Automakers and the fuel-supply industry are already dealing with a multitude of imperatives-more fuel efficient cars, more bio-fuels, plug-in hybrid electric vehicles, pure electric vehicles. Making a push for natural gas vehicles would add yet another set of mandates and incentives, including the creation of a costly new fueling infrastructure.” As Congress considers the appropriate incentives to advance energy security, it should keep in mind that electric vehicles are 3X more efficient than natural gas vehicles.

A recent Ernst & Young analysis concluded that H.R.1380, the Natural Gas Act, which would provide tax incentives for natural gas vehicles, would be a costly investment. The budget impact is approximately $3 billion over five years, $10 billion over ten years, and a whopping $135,000 per vehicle, a high figure driven largely by the need for substantial infrastructure to support the natural gas vehicle market.

We would also like to note that substantial investment is being made to promote natural gas vehicles in the absence of additional government incentives. Chesapeake Energy recently announced its intention to invest in natural gas vehicles in the absence of government incentives.

Conclusions

We would like the Members of the Committee to remember five major points from this testimony.

1. US manufacturers provide the highest value-add of any natural gas consumer. Every dollar the U.S. chemical industry spends on natural gas as a raw material creates $8 of added value throughout the economy. This creates a “chain reaction” for our economy and it means jobs.
2. Unconventional gas could be a game-changer for US manufacturers, especially as a source of competitively priced feedstock.
3. Production of unconventional gas, through the technique of hydraulic fracturing can and should be done in an environmentally responsible manner.
4. Natural gas is a critical component of a balanced US energy policy. The key is to ensure alignment between supply and demand, and to avoid shocks to the market from unwise government policy that restricts supply while artificially increasing demand in the power and transportation sectors.
5. A comprehensive and sustainable national energy policy is long overdue. Absent such a policy we are in danger of repeating an over-reliance on natural gas and a return to the price volatility that destroyed American manufacturing jobs in the last decade.

APPENDIX—ACC STUDY ON SHALE GAS SHALE GAS AND NEW PETROCHEMICALS

INVESTMENT: BENEFITS FOR THE ECONOMY, JOBS, AND US MANUFACTURING ECONOMICS & STATISTICS AMERICAN CHEMISTRY COUNCIL MARCH 2011

Executive Summary

Chemistry transforms raw materials into the products and processes that make modern life possible. America’s chemical industry relies on energy derived from natural gas not only to heat and power our facilities, but also as a raw material, or “feedstock,” to develop the thousands of products that make American lives better, healthier, and safer.

Access to vast, new supplies of natural gas from previously untapped shale deposits is one of the most exciting domestic energy developments of the past 50 years. After years of high, volatile natural gas prices, the new economics of shale gas are a "game changer," creating a competitive advantage for U.S. petrochemical manufacturers, leading to greater U.S. investment and industry growth.

America's chemical companies use ethane, a natural gas liquid derived from shale gas, as a feedstock in numerous applications. Its relatively low price gives U.S. manufacturers an advantage over many competitors around the world that rely on naphtha, a more expensive, oil-based feedstock. Growth in domestic shale gas production is helping to reduce U.S. natural gas prices and create a more stable supply of natural gas and ethane.

In its new report, Shale Gas and New Petrochemicals Investment: Benefits for the Economy, Jobs and US Manufacturing, the American Chemistry Council (ACC) uncovered a tremendous opportunity for shale gas to strengthen U.S. manufacturing, boost economic output and create jobs.

ACC analyzed the impact of a hypothetical, but realistic 25 percent increase in ethane supply on growth in the petrochemical sector. It found that the increase would generate:

- 17,000 new knowledge-intensive, high-paying jobs in the U.S. chemical industry
- 395,000 additional jobs outside the chemical industry (165,000 jobs in other industries that are related to the increase in U.S. chemical production and 230,000 jobs from new capital investment by the chemical industry)
- $4.4 billion more in federal, state, and local tax revenue, annually ($43.9 billion over 10 years)
- A $32.8 billion increase in U.S. chemical production
- $16.2 billion in capital investment by the chemical industry to build new petrochemical and derivatives capacity
- $132.4 billion in U.S. economic output ($83.4 billion related to increased chemical production (including additional supplier and induced impacts) plus $49.0 billion related to capital investment by the U.S. chemical industry)

The scenario outlined in ACC's report is corroborated by trends in the chemical industry. ACC member companies, including The Dow Chemical Company, Shell Chemical, LyondellBasell, Bayer MaterialScience and others have announced new investments in U.S. petrochemical capacity to benefit from available resources and grow their chemical businesses. Some of these investments are being made in areas of the country that have been hardest-hit by declines in manufacturing, improving the outlook in economically depressed areas of the country. Further development of the nation's shale gas and ethane can drive an even greater expansion in domestic petrochemical capacity, provided that policymakers avoid unreasonable restrictions on supply.

ACC supports a comprehensive energy policy that promotes energy efficiency and conservation, energy diversity, and expanded domestic oil and natural gas supply, onshore and offshore. The United States must ensure that our regulatory policies allow us to capitalize on shale gas as a vital energy source and manufacturing feedstock, while protecting our water supplies and environment.

INTRODUCTION

This report presents the results of the analysis conducted to quantify the economic impact of the additional production of petrochemicals and downstream chemical products stimulated by an increase in ethane availability. With the development of new shale gas resources, the US petrochemical industry is announcing significant expansions of petrochemical capacity, reversing a decade-long decline. The petrochemical industry is unique in that it consumes energy as a raw material in addition to using energy for fuel and power. With vast new supplies of natural gas liquids from largely untapped shale gas resources, including the Marcellus along the Appalachian mountain chain, a new competitive advantage is emerging for US petrochemical producers. At a time when the United States is facing persistent high unemployment and the loss of high paying manufacturing jobs, these new resources provide an opportunity for new jobs in the petrochemical sector.

This report assumes a one-time $16.2 billion private investment over several years in new plant and equipment for manufacturing petrochemicals[1]. This investment will create jobs and additional output in other sectors of the economy and also will lead to a 25 percent increase in US petrochemicals capacity and $32.9 billion

[1] The $16.2 billion capital investment by the chemical industry is based on historical capital-output ratios developed from data from the Census Bureau.

in additional chemical industry output. In addition to direct effects, indirect and induced effects from these added outputs will lead to an additional $50.6 billion gain elsewhere in the economy. It will create more than 17,000 jobs directly in the chemical industry. These are knowledge-intensive, high-paying jobs, the type of manufacturing jobs that policy-makers would welcome in this economy. In addition to chemical industry jobs, another 165,000 jobs would be created elsewhere in the economy from this chemical industry investment, totaling more than 182,000 jobs. The added jobs created and further output in turn would lead to a gain in federal, state and local tax collections, about $4.4 billion per year, or $43.9 billion over 10 years.

Thus, based on a large private investment initiative driven by newly abundant domestic supplies of natural gas, a significant strengthening of the vital US petrochemical industry is possible. A reasonable regulatory regime will facilitate this development, while the wrong policy initiatives could derail this recovery and expansion and associated job creation.

The scenario analyzed in this paper that considers a 25 percent increase in ethane is not merely a thought exercise. New investments in petrochemical capacity to utilize this resource advantage are already being made by chemical companies. The assumptions are reasonable and are consistent with public announcements by companies such as Dow Chemical, Shell Chemical, LyondellBasell and Bayer MaterialScience among others.

In addition to providing a productive and job-creating outlet for increased ethane supplies, the development of additional cracking capacity has the indirect effect of supporting natural gas development. Because of the recent development of gas from shale formations, the additional supply has pushed down the price of natural gas. Natural gas is an important fuel for home heating and is a vital input to many US manufacturers. Lower natural gas prices, however, also lower the return on investment for shale gas producers. Some shale gas formations, including the Eagle Ford and parts of the Marcellus are rich in natural gas liquids. By providing a market for the co-produced natural gas liquids, ethane in particular, shale gas production remains economic.

Energy Use and the Chemical Industry

The business of chemistry transforms natural raw materials from earth, water, and air into valuable products that enable safer and healthier lifestyles. Chemistry unlocks nature's potential to improve the quality of life for a growing and prospering world population by creating materials used in a multitude of consumer, industrial and construction applications. The transformation of simple compounds into valuable and useful materials requires large amounts of energy.

The business of chemistry is energy-intensive. This is especially the case for basic chemicals, as well as certain specialty chemical segments (e.g., industrial gases). The largest user of energy is the petrochemical and downstream chemical derivatives business. Inorganic chemicals and agricultural chemicals also are energy-intensive.Figure 1 illustrates the ethylene supply chain from ethane feedstock through petrochemical intermediates and final end use products. Figure 1: A Simplified Ethylene Flow Chart Bottles, Film Low Density Polyethylene (LDPE) and Linear Low Density Polyethylene (LLDPE) Ethylene Ethane Miscellaneous Chemicals Linear Alcohols Ethylbenzene Fibers Ethylene Oxide Food Packaging, Film, Trash Bags, Diapers, Toys, Housewares High Density Polyethylene (HDPE) Housewares, Crates, Drums, Bottles, Food Containers Ethylene Dichloride Vinyl Chloride PVC Siding, Window Frames, Swimming Pool Liners, Pipes Ethylene Glycol Automotive Antifreeze Polyester Resin Miscellaneous Pantyhose, Clothing, Carpets Styrene Polystyrene Resins Miscellaneous Models, Cups,

Insulation Styrene Acrylonitrile Resins

Unique among manufacturers, the business of chemistry relies upon energy inputs, not only as fuel and power for its operations, but also as raw materials in the manufacture of many of its products. For example, oil and natural gas are raw materials (termed "feedstocks") for the manufacture of organic chemicals. Petroleum and natural gas contain hydrocarbon molecules that are split apart during processing and then recombined into useful chemistry products. Feedstock use is concentrated in bulk petrochemicals and fertilizers.

There are several methods of separating or "cracking" the large hydrocarbon chains found in fossil fuels (natural gas and petroleum). Natural gas is processed to produce methane and natural gas liquids (NGLs) that are contained in the natural gas. These natural gas liquids include ethane, propane, and butane, and are produced mostly via natural gas processing. That is, stripping the NGLs out of the natural gas (which is mostly methane) that is shipped to consumers via pipelines. This largely occurs in the Gulf Coast region and is the major reason the US petrochemicals industry developed in that region. Ethane is a saturated C_2 light hydrocarbon; a colorless and odorless gas. It is the primary raw material used as a feedstock in the production of ethylene and competes with other steam cracker feedstocks. Propane is also used as a feedstock but it is more widely used as a fuel. Butane is another NGL feedstock.

Petroleum is refined to produce a variety of petroleum products, including naphtha and gas oil, which are the primary heavy liquid feedstocks. Naphtha is a generic term for hydrocarbon mixtures that distill at a boiling range between 70 C and 190 C. The major components include normal and isoparaffins, naphthenes and other aromatics. Light or paraffinic naphtha is the preferred feedstock for steam cracking to produce ethylene, while heavier grades are preferred for gasoline manufacture. Gas oil is another distillate of petroleum. It is an important feedstock for production of middle distillate fuels-kerosene jet fuel, diesel fuel and heating oil-usually after desulfurization. Some gas oil is used as olefin feedstock.

Naphtha, gas oil, ethane, propane and butane are processed in large vessels or "crackers", which are heated and pressurized to crack the hydrocarbon chains into smaller ones. These smaller hydrocarbons are the gaseous petrochemical feedstocks used to make the products of chemistry. In the US petrochemical industry, the organic chemicals with the largest production volumes are methanol, ethylene, propylene, butadiene, benzene, toluene and xylenes. Ethylene, propylene and butadiene are collectively known as olefins, which belong to a class of unsaturated aliphatic hydrocarbons. Olefins contain one or more double bonds, which make them chemically reactive. Benzene, toluene and xylenes are commonly referred to as aromatics, which are unsaturated cyclic hydrocarbons containing one or more rings. Another key petrochemical feedstock— methane— is directly converted from the methane in natural gas and does not undergo the cracking process. Methane is directly converted into methanol and ammonia. Olefins, aromatics and methanol are generally referred to as primary petrochemicals, and are the chemical starting point for plastics, pharmaceuticals, electronic materials, fertilizers, and thousands of other products that improve the lives of a growing population.

Ethane and propane derived from natural gas liquids are the primary feedstocks used in the United States to produce ethylene, a building block chemical used in thousands of products, such as adhesives, tires, plastics, and more. To illustrate how ethylene is used in the economy, a simplified flow chart is presented in *Figure 1. While propane has additional non-feedstock uses, the primary use for ethane is to produce petrochemicals;, in particular, ethylene. Thus, if the ethane supply in the US increases by 25%, it is reasonable to assume that, all things being equal, ethylene supply will also increase by 25%.

Ethane is difficult to transport, so it is unlikely that the majority of excess ethane supply would be exported out of the United States. As a result, it is also reasonable to assume that the additional ethane supply will be consumed domestically by the petrochemical sector to produce ethylene. In turn, the additional ethylene and other materials produced from the ethylene are expected to be consumed downstream, for example, by plastic resin producers. This report presents the results of an analysis that quantified the economic impact of the additional production of petrochemicals and downstream chemical products.

The report also examines the economic impact of the investment in new plant and equipment needed to enable the petrochemical and derivatives sectors to take advantage of the increased ethane supply. Because the focus of this analysis is the impact of a 25% increase in ethane availability, this analysis does not capture any additional activity that could be generated if methanol and ammonia production were to return or increase to prior levels due to the increased availability of natural gas.

Increased ethane production is already occurring as gas processors build the infrastructure to process and distribute production from shale gas formations. According to the Energy Information Administration (EIA), ethane supply has already grown by roughly 20%. Chemical producers are starting to take advantage of these new ethane supplies with crackers running at 95% of capacity, and several large chemical companies have announced plans to build additional capacity. And because the price of ethane is low relative to oil-based feedstocks used in other parts of the world, US-based chemical manufacturers are contributing to strong exports of petrochemical derivatives and plastics. In 2010, exports in basic chemicals and plastics were up 28% from 2009. The trade surplus in basic chemicals and plastic surged to a record $16.4 billion.

The Development of Shale Gas

One of the more interesting developments in the last five years has been the dynamic shift in natural gas markets. Between the mid-1960s and the mid-2000s,

* All figures have been retained in committee files.

proved natural gas reserves in the United States fell by one-third, the result of restrictions on drilling and other supply constraints. Starting in the 1990s, government promoted the use of natural gas as a clean fuel, and with fixed supply and rising demand from electric utilities, a natural gas supply shortage occurred, causing prices to rise from an average of $1.92 per thousand cubic feet in the 1990s to $7.33 in 2005. Rising prices were exacerbated by the effects of hurricanes Katrina and Rita in 2005, which sent prices over $12.00 per thousand cubic feet for several months due to damage to gas production facilities.

Shale and other non-conventional gas were always present geologically in the United States. Figure 2 illustrates where shale gas resources are located in the United States. These geological formations have been known for decades to contain significant amounts of natural gas, but it was not economically feasible to develop given existing technology at the time. It should be noted, however, that uneconomic resources often become marketable assets as a result of technological innovation, and shale gas is a prime example.

Over the last five years, several factors have combined to stimulate the development of shale gas resources. First was a new way of gathering natural gas from tight-rock deposits of organic shale through horizontal drilling combined with hydraulic fracturing. Horizontal drilling allows producers to drill vertically several thousand feet and then turn 90 degrees and drill horizontally, expanding the amount of shale exposed for extraction. With the ability to drill horizontally, multiple wells from one drilling pad (much likes spokes on a wheel) are possible, resulting in a dramatic expansion of shale available for extraction, which significantly boosts productivity. A typical well might drill 1° miles beneath the surface and then laterally 2,000- 6,000 feet.

The second innovation entailed improvements to hydraulic fracturing (or fracking). This involves fracturing the low-permeability shale rock by using water pressure. Although these well stimulation techniques have been around for nearly 50 years, the technology has significantly improved. A water solution injected under high pressure cracks the shale formation. Small particles, usually sand, in the solution hold the cracks open, greatly increasing the amount of natural gas that can be extracted. Fracturing the rock using water pressure is often aided by chemistry (polymers, gelling agents, foaming agents, etc.). A typical well requires two to three million gallons of water and 1.5 million pounds of sand. About 99.5% of the mixture is sand and water. Figure 3 illustrates these technologies. Another important technology is multi-seismology that allows a more accurate view of potential shale gas deposits.

With these innovations in natural gas drilling and production, the productivity and profitability of extracting natural gas from shale deposits became possible. Further, unlike traditional associated and non-associated gas deposits that are discrete in nature, shale gas often occurs in continuous formations. While shale gas production is complex and subject to steep production declines, shale gas supply is potentially less volatile because of the continuous nature of shale formations. Many industry observers suggest that the current state of shale gas operations are more closely analogous to manufacturing operations than traditional oil and gas exploration, development and production.

The United States is now estimated to possess 2,552 trillion cubic feet (TCF) of natural gas reserves, 32% of which is shale gas (827 TCF) that no one knew how to extract economically as recently as five years ago. This translates into an additional supply of 36 years at current rates of consumption of about 23 TCF per year. Total US natural gas resources are estimated to be large enough to supply over 100 years of demand. In less than two years, the US has sharply reduced gas imports from Canada and liquefied natural gas (LNG) receipts. These new technical discoveries have vastly expanded reserves and will offset declines in conventional associated natural gas production.

To date, the Barnett, Haynesville, and Woodford basins have received the most attention. But not all shale gas formations are identical: some have little or no NGLs. Haynesville is reported to be mostly dry, while Barnet has dry and rich NGL regions. The Eagle Ford shale formation in Texas is close to the existing petrochemical industry and infrastructure and portions are reported to be rich in ethane and other NGLs. The liquids content adds another layer of complexity and economic attractiveness to the shale gas growth story. More recently, the Marcellus basin (by some estimates the largest known shale deposit in the world) has witnessed significant development. Portions of this formation are rich in NGLs but at a distance from the Gulf Coast where much of the existing petrochemical industry exists. Significant development of infrastructure (pipelines, ethane recovery, etc.) would be needed and could also include investment in petrochemical and derivatives capacity. Thus, areas in western Pennsylvania, New York and/or West Virginia could become the next US petrochemical hub. The governor of West Virginia, for example, has recently formed the Marcellus to Manufacturing Task Force to harness business opportunities surrounding development of the Marcellus basin. In addition, the Eagle Ford shale formation in Texas is close in location to the US petrochemical industry (and infrastructure) in the Gulf Coast and reported to be rich in ethane and other NGLs. Better returns from extracting and marketing liquids could provide an added incentive for shale investment beyond profits arising from the thermal value of natural gas from shale deposits.

Higher prices for natural gas in the last decade (especially after hurricanes Katrina and Rita) and the advances in horizontal drilling and hydraulic fracturing (i.e., chemistry in action) changed the dynamics for economic shale gas extraction. The latter technologies allowed extraction of shale gas at about $7.00 per thousand cubic feet, which was well below prices of natural gas during the time just after the hurricanes. With new economic viability, natural gas producers responded by drilling, setting off a "shale gas rush", and as learning curve effects took hold, the cost to extract shale gas (including return on capital) fell, making even more supply (and demand) available at lower cost. Although the path was irregular, average daily consumption of natural gas rose from 60.3 billion cubic feet (BCF) per day in 2005 to 62.0 BCF per day in 2009. Moreover, since the mid-2000s, US-proved natural gas reserves have risen by one-third. In economists' terms, the supply curve shifted to the right, resulting in lower prices and greater availability. During this same time, average natural gas prices fell from $7.33 per thousand cubic feet in 2005 to $3.65 per thousand cubic feet in 2009. In 2010, a recovery of gas-consuming industries and prices occurred. Average daily consumption rose to 66.0 BCF and prices strengthened to $4.14 per thousand cubic feet. Figure 4 illustrates how this new technology's entrance into the market pushed prices lower and expanded supply.

The results of the shift in North American natural gas markets have had the positive effect of lowering prices and expanding supply. Shale gas is thus a "game changer". In the decades to come, shale gas could provide 25% of US natural gas needs, compared to 8 percent in 2008. The availability of this low priced natural gas (and ethane) could improve US chemical and other industry competitiveness. A number of other leading industries, including aluminum, cement, iron and steel, glass, and paper, are large consumers of natural gas that also would benefit from shale gas developments and could conceivably boost capital investments and output.

With rising population and incomes, as well as increased economic activity and regulations, promoting natural gas use in electricity generation would tend to shift the demand curve to the right and move it up along the supply curve. This could partially offset some of the positive gains achieved during the past five years, although further technological developments in drilling and fracturing could spur even more abundant economic resources.

The use of hydraulic fracturing in conjunction with horizontal drilling has opened up resources in low permeability formations that would not be commercially viable without this technology, but there are some policy risks. Some public concern, however, has been raised regarding hydraulic fracturing due to the large volumes of water and potential contamination of underground aquifers used for drinking water, although fracking occurs well below drinking water resources. Limiting the use of hydraulic fracturing would impact natural gas production from low permeability reservoirs. Ill-conceived policies that restrict supply or artificially boost demand are also risks. Local bans or moratoria could present barriers to private sector investment. A final issue is the need for additional gathering, transport and processing infrastructure. The Marcellus and some other shale gas deposits are located outside the traditional natural gas supply infrastructure to access the shale gas.

The United States must ensure that our regulatory policies allow us to capitalize on shale gas as a vital energy source and manufacturing feedstock, while protecting our water supplies and environment. We support state-level oversight of hydraulic fracturing, as state governments have the knowledge and experience to oversee hydraulic fracturing in their jurisdictions. We are committed to transparency regarding the disclosure of the chemical ingredients of hydraulic fracturing solutions, subject to the protection of proprietary information.

Shale Gas and Industry Competitiveness

The developments in shale gas will engender the wider availability of low cost, domestic energy. Because US petrochemicals predominantly use ethane and other natural gas liquids, the competitiveness of the industry is heavily dependent upon the price of these liquids and US natural gas, as well as the price of competitive feedstocks.

As a rough rule of thumb, when the ratio of the price of oil to the price of natural gas is more than 7:1, the competitiveness of Gulf Coast-based petrochemicals and derivatives vis-a-vis other major producing regions is enhanced. In the United States, over 85 percent of ethylene, for example, is derived from natural gas liquids while in Western Europe over 70 percent is derived from naphtha, gas oil and other light distillate oil-based products.

The price of naphtha, gas oil and other light distillate oil-based products are related to the price of oil, a commodity with prices set by global supply and demand. The price of naphtha (in Western Europe, for example) is highly correlated with the price of oil (Brent) as illustrated in Figure 5. As a result, prices for naphtha will parallel the price for oil.

On the other hand, natural gas markets are regional in nature, with the United States and Canada being an integrated regional market. The price of ethane is correlated with US natural gas prices (Henry Hub). This is illustrated in Figure 6. As a result, prices for ethane will tend to parallel the price for natural gas. The correlation has weakened in recent years and other explanatory variables such as the prices of alternative feedstocks (like propane, butane, and naphtha) are important. The latter tend to be correlated with the price of oil.

Thus, the feedstock costs (and relative competitiveness) of cracking ethane and naphtha will follow the respective costs of natural gas and oil. Historically, other factors (co-product prices, exchange rates, capacity utilization, etc.) have played a role as well. This shift toward more and lower-cost natural gas (and disconnect of its relationship with oil prices) has benefitted the US chemical industry, resulting in greater competitiveness and heightened export demand. This helped offset downward pressures during the recession.

Figure 7 shows the long-term trend in the oil-to-gas ratio, from 1970 through 2015. The early- 2000s represent a period in which US petrochemicals were facing competitive challenges. This was in contrast to the 1970s and the period through early-1990s, when US natural gas prices were low and oil prices were high, the latter the result of the Gulf War. In the 1990s, US energy policy favored use of natural gas in electricity generation but did little to address supply. In late- 2000, the first of several large price spikes occurred, resulting in higher US natural gas prices as US supply was constrained. This continued during the next five or so years, with subsequent natural gas price spikes pushing the oil-to-gas ratio down to levels associated with noncompetitiveness. At that time there were numerous concerns about the long-term viability of the US petrochemical industry. Moreover, a number of plant closures occurred during this period and investment flowed to the Middle East and other “remote gas” locations.

As noted, with several shale gas technological developments, learning curve effects, and the hurricanes of 2005 (and subsequent spikes in natural gas prices) the oil-to-gas relationship began to change. With the development of low cost shale gas resources in the United States, the oil-to-gas ratio has improved, from a non-competitive ratio of 5.5:1 in 2003 and 6.3:1 in 2005 to 15.9:1 in 2009 and 17.9:1 in 2010. The current ratio is very favorable for US competitiveness and exports of petrochemicals, plastics and other derivatives. Abundant availability and economic viability of shale gas at prices suggests a continued crude oil-natural gas price disconnect. Moreover, forecasters at the EIA and energy consultants expect high oilto- gas ratios to continue.

Figure 8 illustrates the changing dynamics of natural gas relative to oil from a more long-term perspective. The chart measures the real price of oil (in constant 2009 dollars) relative to this oil-to-gas ratio for the years 1974 through 2010. Five-year moving averages are employed to better illustrate these trends. When the oil-to-gas ratio is high, US Gulf Coast petrochemicals are generally advantaged, as they largely were from 1974 through the late-1990s. But with the promotion of natural gas demand and supply constraints, the situation worsened last decade. Moreover, the real price of oil rose during the past 10 years, which led to advantages among remote locations with abundant natural gas, most notably in the Middle East. With the advent of shale gas, the US petrochemical competitive position is once again evolving, returning closer to the situation which prevailed during the 1980s, when oil prices were relatively high compared to natural gas prices.

Figure 9 illustrates a global petrochemical cost curve for 2010. Using data for 26 major nations and sub-regions, the curve reflects the differences in plant capacity and feedstock slates and shows how the US has moved to a globally competitive position[2]. The scale is not included in Figure 9 as the figure is only intended to illus-

[2] Petrochemical costs vary depending on historical feedstock costs, by-product credits, cost of fuels and other utilities, hourly wages and staffing levels, other variable operating costs, and fixed costs as well as differences in operating rates. The vertical axis reflects the cash (or vari-

Continued

trate the short-run supply curve. The cost curve is built on the cumulative petrochemical capacity from the lowest cost producers (in the Middle East) to the highest cost producers (in Northeast Asia). While the Middle Eastern facilities are substantially advantaged relative to the marginal producers their competitiveness is almost comparable to US ethane-based producers. In the 2010, the Northeast Asian and Western European producers appear to be the least competitive. The latter are not only highcost producers but also have smaller facilities with an average age of around 35 years resulting in substantially higher maintenance spending relative to their global competitors. As recently as 2005, the United States ranked behind Western Europe. With the revolution in shale gas, US producers have moved down the cost curve and now, rank behind Canada and the Middle East.

Figure 10 illustrates the competitive dynamics of petrochemicals and derivatives by examining the strong correlation between thermoplastic exports (as measured in millions of pounds) and the oil-to-gas ratio. As a result of shale gas (and weak industrial demand for gas), the US oil-to- gas ratio has been above 7:1 for several years. The ratio of oil prices to natural gas prices has been over 22:1 recently. This position is very favorable for US competitiveness and exports of petrochemicals, plastics and other derivatives. In 2010, the US Gulf Coast cost position improved so much that the region now is second only to the Middle East in terms of competitiveness. As a result, for example, US plastic exports are up nearly 10% due to this improved position. Furthermore, ethane supplies are tightening in the Middle East and are constrained. The era of low-cost feedstocks is over for some producing nations in that region. This will also aid US competitiveness and may induce capital investment in the United States.With the further development of shale gas, the oil-to-gas ratio is expected to remain high, and the future for the US petrochemical industry appears positive. This analysis seeks to quantify the economic impact of the additional production of petrochemicals and downstream chemical products.

Methodology and Assumptions

The objective of the research was to quantify the effects of private investment in US petrochemicals and downstream chemical products on additional output of the industry, as well as indirect and induced effects on other sectors of the economy. The economic impact of new investment is generally manifested through four channels:

- Direct impacts—such as the employment, output and fiscal contributions generated by the sector itself
- Indirect impacts—employment and output supported by the sector via purchases from its supply chain
- Induced impacts—employment and output supported by the spending of those employed directly or indirectly by the sector
- Spillover (or catalytic) impacts—the extent to which the activities of the relevant sector contribute to improved productivity and performance in other sectors of the economy

The analysis focused on the first three channels. Spillover (or catalytic) effects would occur from new investment in petrochemicals, but these positive externalities are difficult to quantify and thus were not examined in the analysis. These positive effects could include heightened export demand and the impacts on the chemical industry from renewed activity among domestic end-use customer industries. Due to model limitations, the impact on exports cannot be separately identified, but clearly, increased production of petrochemicals would likely lead to higher exports because of enhanced competitiveness.

In addition to added output, the effects on employment and tax revenues also were assessed. To accomplish the goals of the analysis, a robust model of the direct, indirect and other economic effects is needed, as well as reasonable assumptions and parameters of the analysis. To estimate the economic impacts from increasing investment in US petrochemicals production, the IMPLAN model was used. The IMPLAN model is an input-output model based on a social accounting matrix that incorporates all flows within an economy. The IMPLAN model includes detailed flow information for 440 industries. As a result, it is possible to estimate the economic impact of a change in final demand for an industry at a relatively fine level of granularity. For a single change in final demand (i.e., change in industry spending), IMPLAN can generate estimates of the direct, indirect and induced economic impacts. Direct impacts refer to the response of the economy to the change in the final demand of a given industry to those directly involved in the activity. Indirect im-

able) costs on a per pound basis while the horizontal axis reflects the corresponding capacity for the country or region.

pacts (or supplier impacts) refer to the response of the economy to the change in the final demand of the industries that are dependent on the direct spending industries for their input. Induced impacts refer to the response of the economy to changes in household expenditure as a result of labor income generated by the direct and indirect effects.

The analysis was broken into two parts: the one-time change in final demand that occurs during the initial capital investment phase when new plant and equipment are purchased and the ongoing change in final demand that occurs with a 25% increase in ethane production in the United States. It was assumed that production of ethylene and downstream plastics resins would experience a similar increase. Since 99% of all US ethane supply goes into ethylene production, and over 82% of ethylene goes into plastic resins, this linear relationship is a reasonable assumption. Other ethylene derivatives (synthetic rubber, polyolefins, etc.) production is expected to expand as well, but not by as much. Table 1 details the additional chemical industry output generated by a 25% increase in ethane production. The assumption that production of ethylene will increase is reasonable and consistent with public announcements by companies such as Dow Chemical, Shell Chemical, Lyondell Basell and Bayer Material Science, among others.

- In December 2010, Dow Chemical announced it will increase ethane cracking capability on the US Gulf Coast by 20 percent to 30 percent over the next two to three years, and is reviewing options for building a natural gas liquids (NGL) fractionator to secure ethane supplies. The latter provides a new source of NGL supplies, helping to position U.S. petrochemical companies as one of the lowest cost producers of ethylene globally. Both actions are intended to capitalize on the favorable supply dynamics in North America.
- In the Autumn/Winter 2010 issue of Shell Chemicals Magazine, the company discussed how its base chemicals operations in the Gulf Coast region have taken advantage of changing hydrocarbon market dynamics to strengthen its feedstock processing capability. The turnaround in competitive positioning achieved was deemed vital to the success of Shell's chemicals business in the United States and for future security of supply to customers in North American heartland markets.
- Bayer MaterialScience has expressed interest in siting an ethane cracker in West Virginia at one of its two manufacturing complexes in the state, according to press reports. There are no ethane crackers in the Marcellus region. A West Virginia ethane cracker would be the first to serve the hub of chemical manufacturing in the western Pennsylvania/West Virginia area.

The IMPLAN model used to analyze this boost of production was adjusted to avoid double counting the impact of increased petrochemical and intermediate organic chemical demand. In addition, spending for oil and gas production and related services was excluded. Thus, the model was tailored to incorporate an annual increase in spending of $32.8 billion from an expansion of petrochemicals and associated downstream chemical manufacturing activity.

Table 1: Additional Chemical Industry Output Generated by a 25 percent Increase in Ethane Production

	$ Billion
Bulk Petrochemicals and Organic Intermediates	$18.3
Carbon Black	0.2
Plastics Resins	13.1
Synthetic Rubber	1.0
Man-Made Fibers	0.3
Total	$32.8

Lower natural gas costs also could engender new carbon black capacity (in line with new synthetic rubber capacity and higher activity in rubber products). Higher activity in downstream plastic products manufacturing (or processing) would lead to higher sales of plastic additives and plastics compounding. Similarly, higher activity in downstream tire and other rubber products manufacturing (or processing) would lead to higher sales of rubber processing chemicals. These effects are not captured in the analysis. Another effect that is not captured in the analysis is the improved competitive position which would result in higher chemical exports.

Because the model does not include the effects of the investment needed to produce the added $32.8 billion output of petrochemicals that would be generated by the 25 percent increase in ethane supply, the value of the capital investment was separately estimated. Based on the economics and chemical engineering literature, typical capital-output ratios were estimated to range from 0.27:1 to 0.73:1. That is, $1.0 billion in added petrochemical and derivative output could require new capital investment ranging from $270 million to $730 million. Data sources for calculating these capital-output ratios include the Quarterly Financial Report prepared by the US Census Bureau, fixed asset and industry data from the Bureau of Economic Analysis (BEA), and the Corporation Sourcebook prepared by the Statistics of Income Division of the Internal Revenue Service. The capital-output ratio of 0.49:1 that was used was based on an average of ratios calculated. That is, $1.0 billion in added petrochemical and derivative output would require new capital investment on the order of $490 million. The scope of the analysis was limited to the chemical sector and did not include the investment or business activity generated by the extraction, recovery or infrastructure related to delivery of the ethane to chemical plants. It also did not include the effects from investment in development and production of shale gas nor pipeline and other infrastructure development.

The results of the analysis indicate that the added $32.8 billion output of petrochemicals and derivatives would necessitate new capital investment of $16.2 billion. These investments could be a combination of debottlenecking, brownfield and greenfield projects. The composition by asset type for this capital investment was derived using the average historical mix for the chemical industry's expenditures for fixed assets. The fixed asset data from the BEA was used. These assumed spending by asset type were assigned to the appropriate NAICS industry and the IMPLAN model was re-run to incorporate the effects of the new investment. Effects on added output, jobs, and tax revenues from the new investment spending were assumed to be a one-time impact and were modeled as such. Although the spending would likely occur over the period of three years, distinct phases in the project are likely, with engineering and design occurring early, followed by equipment procurement, and then construction and installation. Some overlap of construction activity is possible but assumed to be modest in scope.

Added Output and Job Creation

The output and employment generated by additional ethane utilization in the petrochemical and derivative industries is significant. The additional $32.8 billion in chemical industry activity would generate over 17,000 high-paying, desirable jobs in the chemical industry. Innovative, creative and pacesetting, the business of chemistry is one of the most knowledge-intensive industries in the manufacturing sector. "Knowledge worker" is a term that was originally coined by management guru, Peter Drucker, several decades ago. It refers to employees with university degrees/training whose principal tasks involve the development or application of specialized knowledge in the workplace. A study by Industry Canada showed that 38% of all employees in the US business of chemistry have at a minimum, a university degree. This is nearly double the average in US manufacturing.

Table 2: Economic Impact from Expanded Production of Petrochemical and Derivatives from a 25% Increase in Ethane Production

Impact Type	Employment	Payroll ($ Billion)	Output ($ Billion)
Direct Effect	17,017	$2.4	$32.8
Indirect Effect	79,870	6.6	36.9
Induced Effect	85,563	4.1	13.7
Total Effect	182,450	$13.1	$83.4

In addition, the increased use of ethane by the chemical industry would generate purchases of raw materials, services, and other supplies throughout the supply chain. Thus, nearly another 80,000 indirect jobs would be supported by the boost in ethane production. Finally, the wages earned by new workers in the chemical industry and workers throughout the supply chain are spent on household purchases and taxes generating more than 85,000 jobs induced by the response of the economy to changes in household expenditure as a result of labor income generated by the direct and indirect effects. All told, the additional $32.8 billion in chemical industry output from a 25% increase in ethane production would generate $83.4 billion in output to the economy and more than 182,000 new jobs in the United States generating a payroll of $13.1 billion. This comes at a time when 15 million Americans are out of work. Moreover, the new jobs would primarily be in the private sector. A detailed table on jobs created by industry is presented in Appendix Table 1.

Table 3: Economic Impact from New Investment in Plant and Equipment

Impact Type	Employment	Payroll ($ Billion)	Output ($ Billion)
Direct Effect	54,094	$ 4.3	$16.2
Indirect Effect	74,479	5.1	16.8
Induced Effect	100,549	4.8	16.1
Total Effect	229,122	$14.2	$49.0

Following a decade of contraction in the petrochemical sector, new plant and equipment would be required to use the additional feedstock supplies. A one-time $16.2 billion investment would generate more than 54,000 jobs, mostly in the construction and capital equipmentproducing industries. Indirectly, another $16.8 billion in output and more than 74,000 jobs would be generated throughout the supply chain. Finally, a further $16.1 billion in output and more than 100,000 jobs would be created through the household spending of the workers building, making, and installing the new plant and equipment and those throughout the supply chain. All told, a $16.2 billion investment in the chemical industry would support nearly 230,000 jobs and $14.2 billion in payrolls. These impacts would likely be spread over several years. A detailed table on jobs created by industry is presented in Appendix Table 2.

Tax Revenues

The IMPLAN model allows a comprehensive estimation of additional tax revenues that would be generated across all sectors as the result of increased economic activity. Table 4 details the type and amount of tax revenues that would be generated from a boost in ethane production by 25% and its subsequent consumption by the chemical industry. The additional jobs created and added output in turn would lead to a gain in taxes receipts. Federal taxes on payrolls, households, and corporations would yield about $2.5 billion per year, and assuming historical tax buoyancy, would generate $24.9 billion over 10 years. On a state and local level, an additional $1.9 billion per year would be generated, or $19.0 billion over 10 years.

Table 4: Tax Impact from Expanded Production of Petrochemical and Derivatives from a 25% Increase in Ethane Production ($ Billion)

	Payroll	Households and Proprietors	Corporations and Indirect Business Taxes	Total	Over 10 Years
Federal	$1.0	$0.9	$0.6	$2.5	$24.9
State and Local	$0.02	$0.30	$1.57	$1.9	$19.0

There are also considerable tax revenues generated from the $16.2 billion investment in new plant and equipment. Federal tax receipts would be $3.1 billion, while state and local receipts would be $1.8 billion. While the impact from the new plant and equipment investment would be short-lived, it would nonetheless be welcomed during these times of fiscal imbalances.

Combining the additional federal tax revenues from the added output with tax revenues associated with this private-sector boost in investment, the 10-year revenue addition to the US Treasury would be at least $25.0 billion. Similar large gains in revenues would accrue to the states and various localities.

Table 5: Tax Impact from New Investment in Plant and Equipment ($ Billion)

	Payroll	Households and Proprietors	Corporations and Indirect Business Taxes	Total
Federal	$1.4	$1.2	$0.5	$3.1
State and Local	$0.04	$0.4	$1.3	$1.8

Future Research

The economic impact of the additional production of petrochemicals and downstream chemical products was quantified in this report. Added output, jobs and tax revenues were all evaluated based on the additional output in chemicals only. A number of other manufacturing industries, including aluminum, cement, iron and steel, glass, and paper also are large consumers of natural gas that would benefit from shale gas developments and could conceivably boost capital investments and output. In addition, the rubber and plastics products industries could similarly expand. Further analysis could be conducted to incorporate these effects. In addition, the economic effects arising from the development of shale gas for other non-industrial markets and for possible exports could be examined. Finally, the renewed competitiveness arising from shale gas has enhanced US chemical industry exports, production and jobs. These positive trends will persist and will need to be quantified. Combined, these positive effects could be comparable in scope to the primary findings of this analysis.

Conclusions

The economic effects of new petrochemicals investment in the United States are overwhelmingly positive. Recent breakthroughs in technology have made it productive and profitable to tap into the vast amount of shale gas resources that are here, in the United States. Barring ill-conceived policies that restrict access to this supply, further development of our nation's shale gas resources will lead to a significant expansion in domestic petrochemical capacity. Indeed, a new competitive advantage has already emerged for US petrochemical producers. And this comes at no better time: The United States is facing persistent high unemployment and the loss of high paying manufacturing jobs. Access to these new resources, building new petrochemical and derivative capacity, and the additional production of petrochemicals and downstream chemical products will provide an opportunity for more than 400,000 jobs—good jobs. A large private investment initiative would enable a renaissance of the US petrochemical industry and in this environment, a reasonable regulatory regime will be key to making this possible.

ACC's Economics & Statistics Department

The Economics & Statistics Department provides a full range of statistical and economic advice and services for ACC and its members and other partners. The group works to improve overall ACC advocacy impact by providing statistics on American Chemistry as well as preparing information about the economic value and contributions of American Chemistry to our economy and society. They function as an in-house consultant, providing survey, economic analysis and other statistical expertise, as well as monitoring business conditions and changing industry dynamics. The group also offers extensive industry knowledge, a network of leading academic organizations and think tanks, and a dedication to making analysis relevant and comprehensible to a wide audience.

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Appendix Table 1: Jobs Generated by the Expanded Production of Petrochemical and Derivatives from a 25% Increase in Ethane Production

	Direct	Indirect	Induced	Total
Agriculture	-	**1,280**	**1,977**	**3,256**
Mining & Utilities	-	**5,319**	**540**	**5,859**
Oil and gas extraction	-	3,072	154	3,226
Natural gas distribution	-	969	52	1,022
Electricity generation and distribution	-	782	232	1,014
Other mining and utilities	-	496	103	599
Construction	-	**3,048**	**837**	**3,885**
Durable Manufacturing	-	**3,363**	**1,924**	**5,287**
Primary and fabricated metals	-	1,516	425	1,941
Machinery, electrical equipment, and instruments	-	802	230	1,032
Computers and electronics	-	378	143	521
Other durable manufacturing	-	666	1,126	1,792
Nondurable Manufacturing	**17,017**	**6,898**	**2,701**	**26,616**
Petroleum and coal products	-	699	39	738
Chemicals	17,017	4,522	370	21,908
Other nondurable manufacturing	-	1,678	2,293	3,970
Trade	-	**11,857**	**17,101**	**28,957**
Transportation	-	**5,936**	**2,607**	**8,542**
Information	-	**1,627**	**1,845**	**3,472**
Finance, Insurance and Real Estate	-	**4,823**	**9,863**	**14,686**
Services	-	**35,720**	**46,169**	**81,889**
Professional and technical services	-	8,167	3,965	12,132
Scientific R&D services	-	4,644	216	4,860
Management of companies	-	4,531	734	5,265
Administrative and support services	-	9,127	4,666	13,793
Other services	-	9,252	36,588	45,840
TOTAL JOBS	**17,017**	**79,870**	**85,563**	**182,450**

Appendix Table 2: Jobs Generated from New Investment in Plant and Equipment

	Direct	Indirect	Induced	Total
Agriculture	-	**427**	**2,334**	**2,761**
Mining & Utilities	-	**833**	**638**	**1,470**
Oil and gas extraction	-	208	181	389
Natural gas distribution	-	86	62	148
Electricity generation and distribution	-	270	274	544
Other mining and utilities	-	269	121	390
Construction	**17,537**	**820**	**983**	**19,339**
Durable Manufacturing	**31,169**	**13,779**	**2,259**	**47,208**
Primary and fabricated metals	3,899	6,895	499	11,293
Machinery, electrical equipment, and instruments	22,304	2,799	271	25,374
Computers and electronics	1,999	1,653	167	3,819
Other durable manufacturing	2,968	2,432	1,322	6,721
Nondurable Manufacturing	-	**2,387**	**3,187**	**5,573**
Petroleum and coal products	-	75	46	121
Chemicals	-	401	437	837
Other nondurable manufacturing	-	1,911	2,704	4,615
Trade	-	**7,829**	**20,070**	**27,899**
Transportation	-	**4,179**	**3,062**	**7,241**
Information	**5,388**	**3,109**	**2,172**	**10,668**
Finance, Insurance and Real Estate	-	**5,836**	**11,618**	**17,454**
Services	-	**35,281**	**54,228**	**89,509**
Professional and technical services	-	9,984	4,664	14,647
Scientific R&D services	-	1,034	254	1,288
Management of companies	-	3,362	865	4,228
Administrative and support services	-	12,329	5,486	17,815
Other services	-	8,573	42,959	51,532
TOTAL JOBS	**54,094**	**74,479**	**100,549**	**229,122**

The CHAIRMAN. Thank you very much. Thank you all for your excellent testimony and all of the work that went into developing it, particularly all the 3-years of work there at MIT in this future of natural gas study.

Let me start with a question that I think both Dr. Gruenspecht and Dr. Moniz alluded to. That is this whole issue of whether or not we wind up seeing our natural gas integrated into a world market. Whether there's an evolution of an integrated, global natural gas market, I think is the way it was referred to.

Frankly I have some concerns when I hear about that potential because I see what's happened to us in oil. I mean, we produce substantial amounts of oil. In my State I noticed that regardless of the fact that it costs not a dime more to produce oil from 1 day to the next, the price is the same. The price that we pay at the pump, that consumers pay at the pump goes up dramatically because of something that happens in Saudi Arabia or Libya or wherever.

It concerns me if we're going to see the same kind of global market for natural gas which would be subject to the same kinds of volatility and price shocks that we've seen in the world market for oil. Is that an unjustified concern, Dr. Gruenspecht?

Mr. GRUENSPECHT. I would say all else equal increased demand for North America natural gas whether domestically or from the rest of the world would tend to raise its price just as increased demand for other commodities like agricultural commodities tend to raise their prices. We have not looked particularly at U.S. exports of gas, but we have looked at gas cases with increased demand and we do see higher prices.

Of course it's also true that higher global demand for domestically produced energy or non energy commodities also tends to boost the economy and employment. So I guess the question is how you weigh those things. As suggested by my testimony I think an analysis of the potential impacts of LNG exports would depend on both the domestic side of the picture, involving domestic natural gas resource and production developments, and on the future evolution of the global natural gas market.

Again, this issue is whether that market has gas on gas competition. Then the issue becomes—how competitive the U.S. would be as a source of feedstock for creating liquefied natural gas versus other stranded gas throughout the world. Convergely, retaining the traditional linkage of LNG to oil prices which would maybe give more room for U.S. sourced gas to be a feedstock in a world market.

I guess the other aspect of this issue is this potential of shale gas as an alternative to LNG in the other parts of the world. That could also play a role. So I agree with you. It's just a very complex issue.

The CHAIRMAN. Dr. Moniz.

Mr. MONIZ. First of all I believe there is the justification for concern and to addressing this issue. However, I would offer a few reasons why we, in the end, come down on advantages, net advantages, for the country to support development of a global market. Recognizing it will be very difficult and take a long time for that to happen, especially given the structure of the markets in Asia.

But I think the, in this case, compared to oil first of all there would appear to be less leverage for cartel like behavior. At its core, natural gas has a lot of substitution possibilities in the other way as well. That is, it can be substituted out in the power sector. It can be substituted out in the industry sector.

For example, natural gas liquids verses NAFLA for ethylene production. Right now we have a competitive advantage with that. But that could be substituted out.

It's the analog of what I mentioned for the—in the gas and transportation. What is critical is to have substitution possibilities. With oil in the transportation sector we fundamentally don't have it to any serious degree today, whereas gas, as I say, has these substitution possibilities.

So in that context we see lower prices for the United States. We see, at least for some time in our models and they should be taken with a grain of salt or a cup of salt, the—what we see is the main impact as lower prices and higher demand, not actually materially impacting domestic production. We see that that market would help our allies, like a Germany etcetera, which in turn helps us in our geopolitical flexibility.

So net, we come down there. But there's no question there is the concern on import dependence.

The CHAIRMAN. Mr. Biltz, did you want to make a comment?

Mr. BILTZ. Yes, thank you, Mr. Chairman.

From an industrial perspective this is one of the very few points we disagree with MIT in the study. Our perspective is that there is a global market in gas today. It's very closely tied to the oil pricing. The U.S. market today is disconnected from that, our natural gas abundance and the shale with which it's produced in provides a distinct competitive advantage, as was just mentioned.

Should that become truly tied to the global market that competitive advantage that manufacturers enjoy would disappear. The addax advantage that I talked about earlier would disappear. So our view from a manufacturing standpoint is we think the U.S. would be better served to use that gas to produce products, export those products with an addax impact to the GDP of the country as opposed to a one time export of the natural gas.

The CHAIRMAN. So you think we should take action. We should not be encouraging the import and export of natural gas. We should try to keep our domestic natural gas market somewhat insulated from the global market?

Mr. BILTZ. We would agree that it's a very complex area. As a company we strongly support free trade. But there is a competitive advantage enjoyed today that does allow us to export. To the extent that supply and demand wind up out of balance that puts that at a very critical juncture.

So it's not simply a matter of LNG import export. It's the whole aspect of supply and demand and how those balance out.

The CHAIRMAN. Thank you very much.

Dr. Moniz, did you want to make one more comment? I've run over my time, but go ahead.

Mr. MONIZ. I just have a brief comment that first of all, as Mr. Biltz said, we do disagree on this. I certainly could not characterize there as being a global market. There are 3 large regional markets with very, very different pricing structures.

I would just end by pointing out the irony that the MIT professor is supporting the free market.

[Laughter.]

The CHAIRMAN. Alright.

Senator Murkowski.

Senator MURKOWSKI. Thank you, Mr. Chairman.

Mr. Biltz, I appreciate your testimony and the reminder to us all that in order to be effective in creating jobs and ensuring that our U.S. businesses are competitive we really do have to have an energy policy that is comprehensive. I also appreciate your written testimony which endorses revenue sharing. That's not an issue that's before us today, but it is something that will come before this committee next week. I appreciate you weighing in on that.

Dr. Gruenspecht, let me ask you about the recent article that came out of the New York Times regarding the future of natural gas. It was a pretty negative series of articles. I think the Times own public editor took strong exception with the bias that was displayed in these articles.

But it's my understanding that the articles were based in part on emails that were leaked by senior officials within EIA. I think it goes without saying that the Energy Committee relies on EIA for independent and impartial energy information. We then use this information to hopefully make good strong policy.

So in light of the testimony that you've given us today, in light of the published reports by EIA, I am assuming that EIA considers our shale gas resources in this country to besignificant and that you stand by that. I'd also like to know how this stuff got out there. Can you give me a little more background on it?

You have to admit that when those came out it sure raised a lot of eyebrows. I think it deserves some kind of an explanation as to where we are at this point.

I think you need to push that button there.

Mr. GRUENSPECHT. I want to be heard I guess.

[Laughter.]

Senator MURKOWSKI. Of course we want you to be heard.

Mr. GRUENSPECHT. First let me say that we've carefully looked at the New York Times article. We found nothing in it that causes us concern regarding the methodology, data and analysis that underlie the shale gas projections that we've published and that we've shared with you.

I guess I would say a key principle for EIA is to look at the data. The data clearly show that shale gas has rapidly become a significant source of domestic natural gas supply as I've reviewed in my testimony. It's grown to 23% of production for 2010. Production and production share growth has continued into 2011.

Again, we recognize there are uncertainties. But that's not what the New York Times article was about. The New York Times article was suggesting, I believe, some bias of some sort. We do not see that.

In fact, I know EIA staff explicitly pointed the Times reporter to the extensive section of the 2011 Outlook on shale gas uncertainties. But it was not mentioned in the article. I'm not a media critic. You know, I guess there's a famous saying, don't get into arguments with people who buy ink by the barrel, or something.

But I really do believe that EIA is doing a solid job in effectively tracking the emergence of shale gas in the U.S. energy system and thoughtfully reflecting it in our projections. It's something that a government agency, frankly, could not be on top on. It's moving very, very quickly. To stay in touch we need to access the best available information and incorporate it into our outlook. I think that's really what we've done.

Now, going back to your question about the emails. I don't think the characterization is exactly right there. Most of the emails are largely to and from a person who was hired by EIA in 2009 as an intern and later developed into an entry level position.

I would say that the emails as posted on the Times' website were heavily redacted and redacted in ways that I think provide misleading information on their context. The folks up on the other side of the Capitol, were very interested in this subject and had asked us for the unredacted versions of the emails and information as to how we develop our shale gas work. I can't tell you that EIA is 100% right with its projections, but again, we've emphasized the uncertainty. We do pride ourselves on being transparent; and we have been transparent. We provided them with the unredacted emails. We'd be happy to provide you with similar information.

We want to be really open about this as we do stand behind our shale gas work.

Senator MURKOWSKI. I think it is important that you do make that statement, do make that commitment because I think in our work here in the committee, again, we look to you for scientifically rigorous and impartial data. If that now has been caused to be in question because of this I think that's a real loss to us as policymakers. We need to know that we can rely on that.

So if you have additional information and background that you can give the committee, I think that that would be appreciated. I know that you've had an opportunity to be over on the House side as well. But——

Mr. GRUENSPECHT. It's a big stack. You can have it.

[Laughter.]

Senator MURKOWSKI. Alright. This is why we have all these fine people that sit behind us and pour over this. But this is an important issue for us to understand what the resource is. When stories like this come out that cause doubt as to the reliability of the data, I think it is important to try to air that. So I'd appreciate anything that you can do to help us with that.

Thank you, Mr. Chairman.

The CHAIRMAN. Thank you.

Senator Manchin.

Senator MANCHIN. Thank you, Mr. Chairman. Thank all of you 3 for being here. We appreciate it very much.

As West Virginians you know we've been blessed with a lot of natural resources, coal being predominantly. Natural gas, we just found the Marcellus shale on the 3 States of New York, Pennsylvania and West Virginia. We have a really emerging biofuels with our chemical industry. We have a tremendous renewables in our wind farms on the largest wind farms east of the Mississippi is in West Virginia.

So with all that we've been very, very pleased and very blessed. As you know, coal has been on the tack and the EPA moving is rapidly as they are without having anything in place. I'll ask this—I have 2 parts. But Mr. Biltz first of all from the coming from the manufacturing part.

Are you concerned about the spike in prices as far as the cost of energy and especially your presence in our State that could really disrupt your global presence in America and without having an alternative as coming on in the same like price range?

Mr. BILTZ. It absolutely is a large concern to us. What we continue to look at as policy or other actions that move the demand well out ahead of the supply.

Senator MANCHIN. Right.

Mr. BILTZ. So for us trying to keep that balance between supply and demand is absolutely critical. We believe market forces work that affect. We can help those, for example, in West Virginia. We're working very hard on some carbon capture technology, running a pilot plant, a successful pilot plant right now.

Senator MANCHIN. Yes, you are. Alstom.

Mr. BILTZ. We look to find ways—yes, with Alstom. We look to find ways to do more of that to keep the balance across all opportunities in energy space.

Senator MANCHIN. Mr.—Dr. Moniz, I would ask on with, you know, our concern environmentally with shale right now is we don't know. As you know New York is about shut down and has very little exploration going on. Pennsylvania is throttling pedal to the metal. We're kind of in between. With that being said in shale and we have a chance at the cracker coming back and if we have 1 or 2 cracker, we're back in the ball game again manufacturing as you mentioned with all the wet products coming off of it.

What do you see that we should be concerned about? We're concerned about the injection we're having with one major supplier of the chemicals that go into the injection that won't reveal the contents because they're afraid to trade breach, if you will. What should we be, as the State of West Virginia, be very much concerned environmentally and how do we bridge that or get past that with the Marcellus development?

Then you've got Utica coming on in Ohio, I understand.

Mr. MONIZ. Certainly in terms of the fracking fluids issues. As I said, we strongly recommend a required disclosure of all the contents. We have been completely unconvinced by these arguments of proprietary advantage.

Senator MANCHIN. Agree.

Mr. MONIZ. Whatever the case I think the public interest overrides it.

Having said that, we found—we have not found any evidence of the fracking itself harming the shallow, the water resources. But it's a very large scale activity. There clearly have been problems. We have, in the report, a 5-year summary of all of the major environmental incidents that we could find. Half of them were from faulty well completion. It's the cement, the cement, the cement.

Right now, we have variable State regulations. We think that all the State regulations should be brought up to the highest standards and of course, enforced. That's very critical.

The second issue is, I said, these regional, this integrated water management plan. Absolutely critical. In Pennsylvania they have the challenge of not having the kind of EPA regulated disposal infrastructure, disposal well infrastructure that one finds in some of the more mature producing regions.

So things like recycling of fluids, absolutely critical.

Not having surface spills. Surface spills are the second largest major environmental impact.

Senator MANCHIN. Right.

Mr. MONIZ. So we view, we think we need tough regulation. When we have gone around and spoken about this our advice, whether asked or not to the companies, is you should be seeking strong regulation, especially as the larger companies move into this. It seems to me it's to their benefit to get out ahead of this and work with the States.

Senator MANCHIN. I have one final question, if I may.

First of all, right now natural gas has been used as a combined cycle as far as impeaking. It has not been base load. Now with the production of gas and what we found, I and hear in your testimonies, looking more at it from a base load.

As we convert some of our older plants and the coal plants some of them have 40 years or older. As we have been upgrading some of our plants as far as with carbon capture as you know we have the mountaineer plant in commercial development.

Mr. MONIZ. Yes.

Senator MANCHIN. It looks very promising. But with that being said, the scrubbers and the CPRs and all the things that's been done to point. We're getting pushed by the EPA basically to move further with air quality. But also we have a lot of plants that could be converted with the scrubbers and CPRs and then move with the filtration on the back end.

With all that happening and the plants that basically are, should be cycled out, the old coal fired plants. Working with the utilities I think they would come up and convert some of those to a combined cycle natural gas that would be base loaded. Do you believe it's feasible to base load off of natural gas the way we base loaded off of coal and nukes?

Mr. MONIZ. Yes. So the first, Senator Manchin, I wouldn't say that NGCCs have really been used in a peaking mode. It's more a mid load variation as opposed to turbines.

Senator MANCHIN. Right. Right.

Mr. MONIZ. Which are used for the real peaking. AThose were not part of our—we didn't have, we had no substitution, if you like, on those. So those are needed for reliability of——

Senator MANCHIN. So you got to have a main balance of that?

Mr. MONIZ. Right. So but on the NGCC plants in our modeling, we did include a transmission constraints and the need to maintain variable load capability. So that was already part of our consideration. With the large supply we could do substitution as well. Indeed, the issue was again for these old inefficient coal plants that—those 45 year old——

Senator MANCHIN. Right. Sure.

Mr. MONIZ. 30% efficient plants without any scrubbers. I think we all understand that the economics of a retrofit——

Senator MANCHIN. Sure.

Mr. MONIZ. They don't make any sense. In fact, you could probably build a brand new NGCC plant for the same cost as putting a scrubber on that plant. So I think we will see a lot of that no matter what the regulations are. But certainly a push toward, especially mercury control, would accelerate that.

Senator MANCHIN. Thank you all so much.

Sorry.

The CHAIRMAN. No problem.

Senator Landrieu.

Senator LANDRIEU. Thank you. Let me begin, Mr. Biltz, thanking you for your endorsement of revenue sharing for the Gulf Coast

States. Dow has a tremendous presence in our Nation, but particularly along the Gulf Coast. We're very grateful for your support.

You say one way to maximize the transformational value of increased oil and gas production in the OCS is to share the royalty revenues with coastal States. You also go on to say, and use a portion of the Federal share to help fund research. I couldn't agree with you more. We'll be working on that exact policy later on this week with this committee. So I thank you.

I want to ask the question about the conclusion that it seems like you all have reached that natural gas is a game changer. Dr. Moniz, you stated that and also the EIA. Did you all—I don't want to ask both of you. Did you all arrive at this conclusion independently, the EIA and your study that natural gas could be a game changer for U.S. independence for environmental improvements and economic transformation? Yes or no? Or did you all use the same studies to come to that agreement or that conclusion?

Mr. GRUENSPECHT. EIA arrived at its, Outlook based on work we've been doing for a long time. Again, that means by following the data and looking at the resources——

Senator LANDRIEU. You trust the data that you followed and you're confident of your conclusions?

Mr. GRUENSPECHT. The data—look there's a—if EIA was a library there's a data part and those are facts. Frankly, there are projections. Projections are just that. They involve modeling. They involve assumptions. But the data we followed. We are——

Senator LANDRIEU. But based on the facts in the library what is your conclusion about the future?

Mr. GRUENSPECHT. The facts in the library are that with 23% of U.S. natural gas production having come from shale gas last year and a larger percentage coming this year, its impact is already happening. On the issue of the resources we are working hard to keep up. Again, the U.S. Geological Survey is expected to come out with a new evaluation of the Marcellus Shale which will be very important.

Senator LANDRIEU. The reason I ask you that——

Is because following up what Senator Murkowski said. We depend on you to give us the information so that this committee and Congress——

Can make the wisest decisions possible relative an issue that is extremely important to our constituents and that is the energy sufficient, self sufficiency of the United States moving to more independence. Right now on their minds is jobs. According to what Mr. Biltz said, if we do this right we could potentially create hundreds of thousands of jobs and tremendous wealth for a Nation that desperately needs it.

Now this New York Times article which I have, which the good Senator from Alaska was referring really challenges you and your agency. So do you accept this challenge or what do you have to say to the New York Times and to others that your data can be trusted?

Mr. GRUENSPECHT. Again, I think we're very comfortable with where we are and we've seen nothing of the New York Times report that would cause us to change our view.

Senator LANDRIEU. Dr. Moniz, let me ask you.

Mr. MONIZ. Yes.

Senator LANDRIEU. You're one of the 4 most universities in the world. You've been studying this for 3 years. So, state again for the record. Do you think natural gas has a future in America? Is it a game changer?

Mr. MONIZ. Yes. In fact, we've called it a paradigm shift game changer, yes. In fact going back to your original question, let me just emphasize that in our supply analysis which is very extensive, very transparent, statistical methods are all laid out.

Our data did not come from EIA. They came from the potential gas committee, very highly respected group out of Colorado mines, out of the USGS, out of ICF. We had a team of 5 working on this for 3 years, a lot of well by well analysis and that's where we get our whole distribution of resources.

I'll be honest on the New York Times article, if I may say, this is frankly very disappointed that, you know, I and the supply team were not consulted——

Senator LANDRIEU. Let me ask you this because I've got one more question because I'm disappointed in it as well. You know, it's sort of like staring a gift horse in the mouth. I mean, here is a supply that's domestic. It's 40% cleaner than some of our traditional sources that we're using. It's available spread, you know, not equally, but shared widely among States in the United States.

There seems to be this sort of behind the scenes push back. It's too good to be true. It can't possibly be true. I think we need to break through on this.

My last question because my time is out. On the MIT report you said that environmental impacts of shale are challenging. Anything is challenging. Coal, oil, nuclear, there's nothing that is not challenging.

But what I focused my eyes on is the word manageable. But you said it's challenging but manageable. So could you give us 30 seconds of what are sort of the manageable components that we've got to underlie so that we can tap into this really phenomenal resource that we seem to be discovering?

Mr. MONIZ. Those words were very carefully chosen. The manageable part means, as said earlier, it means really having excellent requirements on well completion. It really means having good sensible, strong regulation on surface water management.

You know, there was some issues, clearly, in terms of using some surface water treatment plants that would not, you know, we just have to have a very good, sound, water management plan. That's the key.

Senator LANDRIEU. That can be done at the regional level?

Mr. MONIZ. Also, yes.

Senator LANDRIEU. It can be done regionally.

Mr. MONIZ. Regional level. Also the other thing I would say is that issue such as introducing the technologies of water recycling, for example, are very important, not only for managing the water, but for their indirect effects of reducing, for example, potentially hundreds of heavy truck movements that would otherwise be required.

So that's what I mean by——

Senator LANDRIEU. By manageable. Thank you.

The CHAIRMAN. Senator Udall.

Senator UDALL. Thank you, Mr. Chairman. Good morning, gentlemen. It's been very helpful. This is an exciting set of developments. Also important questions have been raised.

Mr. Moniz, if I could start with you. In your testimony you touched on the fact that the vast majority of known gas resources, I think, are located in 3 regions, North America, Russia and the Middle East. That these resources are even, and I'm going to quote you, "Even more geographically concentrated than oil."

I sit on the Intelligence Committee and the Armed Services Committee and that drives me and others to be really keenly attuned to geopolitics, particularly how oil affects our national security. Could you talk a little bit about the potential geopolitical implications of natural gas, particularly in a post Fukushima world where more countries may be looking to import gas to replace nuclear power? You've heard the announcement from the Japanese leadership recently, and Of course the Germans have now changed course yet again on their supporter of nuclear power.

So, just the——

Mr. MONIZ. Sorry.

Senator Udall, so the geopolitics, as we did say, are complex. They are roughly 70% of the recoverable resources are in those 3 regions that you say. However, I do want to add that that did not include unconventional resources outside the United States because our feeling was it was too uncertain. Although now the EIA has just this recent report which they also say it's uncertain. But it's a very, very substantial amount of shale gas.

So if, for example, China really can develop an appreciable part of their estimated 1,200 trillion cubic feet of shale gas, that has a major implication on the Asian market, where, of course, Japan is now playing. Maybe it will lead to different market structures.

In Europe, huge issues. Germany, we all know the problems they've had with their Russian supply. They're desperate to diversify. There are substantial resources, shale resources in Poland, in France. The latter has said they don't want to develop them at the moment. Poland will.

But that plus the great game around the Caspian which you are, no doubt, involved in, is huge. Will the Caspian gas move to Europe through Turkey? Will it go through Russia? Will it have—will it go east to China?

So these are big issues that will affect the market structure. All we can do is, in our view, play in the game. In fact, one of our observations is our view that natural gas has not been given the attention, geopolitically frankly, in our Department of State as we form our foreign policy.

Senator UDALL. I could use the rest of my time interacting with you on this topic. But I look forward to more conversation. Potentially this is the subject of a hearing not only in the Foreign Relations Committee, but perhaps even in the Armed Services Committee.

Mr. MONIZ. I might say that my group and I are available to any member, any time to come and explain our work.

Senator UDALL. You—and I just want to ask a question for the record and then I want to move to my final question before my time expires.

You touched on this in your, both in your report, but then in your comments about the risks of shale gas drilling. But you have suggestions for addressing that risk including following best practices for casing and cementing. Do you think current best practices for cementing and casing are sufficient to protect ground water from the materials in the well bore or is more R and D needed to improve industry methods in this area?

Again, I want to just—I'm going to move on. But I'm going to let you know that I'm asking you that question for the record.

Senator UDALL. So let me move to my third question. The MIT report discusses that the upfront costs of natural gas vehicles are significantly higher in our country compared to other countries. For example, your testimony states that factory produced vehicles in the U.S. are more than $3,300 more expensive than in Europe.

Why are the upfront costs for CNG systems for vehicles so much more expensive in the U.S. than they are in the rest of the world?

Mr. MONIZ. I wish I understood. But we certainly think this needs to be addressed.

First of all, also for aftermarket conversion the costs in the United States driven, I think, through regulatory requirements, are just off scale compared to what they are in other places.

Second, in terms of the new car market in Europe you can get a bi-fuel vehicle for a lower incremental cost than here for a simple CNG vehicle. This does not seem to make sense. I think, frankly, it was tied up in a perhaps, unintended consequences of certain kinds of credits for alternative fuel vehicles. So this is something that really deserves more study and may be amenable to legislative action.

Senator UDALL. The vehicle you just described, so it would run on natural gas, on liquid fuels in Europe.

Mr. MONIZ. In Europe. But you can buy a VW bi-fuel vehicle at a smaller incremental cost then the Honda available in the United States as a pure natural gas vehicle.

Senator UDALL. So we may have something to learn from how the Europeans who are embracing this challenge.

Mr. MONIZ. Yes, and maybe how we are putting in alternative fuel incentives in our legislation.

Senator UDALL. Thank you, Doctor.

Thank you, Mr. Chairman.

The CHAIRMAN. Let me ask a few other questions here. One of the issues, I think, that was alluded to in your MIT report, Dr. Moniz, is the possibility of boosting the usage of natural gas in the power sector by having a dispatching order of generation linked to some environmental metric so that I gather you would have, you would build in a sort of bias toward more use of natural gas in the dispatching that occurs. I think you also make reference to the fact that there is a lot of natural gas fired generation capacity that is not utilized to a very great extent, right?

Could you maybe elaborate a little more on how that might work and this concept of environmental dispatch, if that's the right phrase to use?

Mr. MONIZ. Of course today on the basis of economic dispatch than gas tends to be last in line for the simple reason that the marginal cost is almost entirely the fuel cost. Whereas in other, in coal or nuclear, it's—well nuclear especially, it's the opposite. The cost is all in the fixed cost and essentially nothing in the fuel cost. So the marginal cost is quite low.

So basically, anything which would change that dispatch order. For example, a carbon—a decision that for carbon reasons we are going to dispatch first, lower carbon. That would have this impact.

Clearly the simplest policy approach would be essentially a 20 dollar per ton price on CO_2 emissions. That is probably, you know better than I, but that is probably not in the cards at the moment.

The CHAIRMAN. I think you also made reference to work needing to be done with regard to the full life cycle emissions of greenhouse gases from natural gas. I think there have been some studies recently that have suggested that the emissions of natural gas are substantially higher than others fuel feedstocks, than previously estimated if you do look at the full life cycle. What could you tell us about that?

Mr. MONIZ. We do think there's a lot of uncertainty at the moment. I should add that all of the economic modeling that we did already includes these emission factors that were the EPA standard for many years. So we have included that already.

However, there are some suggestions that there may be much higher emissions in the shale production. I can't say that we can confirm or categorically deny that. What we do recommend is a joint DOE/EPA study based upon data that looks at the so called fugitive emissions for production of all fossil fuels, coal, gas, oil. Let's get it on equal footing and find out.

Our own estimates suggest that there still remains the order of a factor of 2 improvement in net CO_2 emissions for a natural gas combined cycle plant verses a coal plant.

The CHAIRMAN. One other issue that I wanted to explore a little bit is the implications of all this new natural gas that's been discovered for the whole idea of carbon capture and storage, CCS. It strikes me that if we're going to have an adequate and ample supply of natural gas at low prices for a long time for the future, the viability of a lot of this CCS work is brought into question, just whether or not it's economically feasible to try to deal with the issue of greenhouse gas emissions that way. I'd be interested in any of you commenting on that.

Mr. Biltz, you said you folks are engaged or participating in a project in West Virginia related to CCS. So maybe you have some expertise on this?

Mr. BILTZ. From our perspective the carbon capture has a great benefit in terms of reducing carbon and helping transition toward a low carbon economy with regards to coal plants. There's certainly other ways to achieve the goal. We, for example, would put energy efficiency right up as our very first choice. Anything moving toward energy efficiency we would support as a company before we get down the path of picking CCS or other alternatives.

But our pilot plant in West Virginia has been successful. We're looking at larger operations for that either as retrofits in conventional coal facilities or as part of new higher efficient facilities.

The CHAIRMAN. So there's nothing in the changed outlook on natural gas that causes you to change your enthusiasm for CCS?

Mr. BILTZ. No, in principle. We've not reached a point of looking at natural gas as the silver bullet. We believe that any energy solution from America is going to involve all energy fuel sources, carbon through coal or nuclear included. Finding solutions across all the fuel sources are important.

The CHAIRMAN. Anybody else want to make a comment?

Mr. GRUENSPECHT. Yes, I'll make a comment. Without some kind of policy related to carbon dioxide, I think we al know that CCS in the electric power sector is pretty challenging. I would say that carbon capture in other sectors where there's more of a pure stream of carbon dioxide could be attractive in the context of enhanced oil recovery for example.

We're talking about natural gas today, but we often talk about oil. Certainly CO_2 assisted EOR, you know, is an important technology. There's been a lot of natural sourced CO_2 coming some out of your State, for example, that goes into oil recovery.

The potential's there at least to develop some of the technology. But actually getting it into the electric power sector without some kind of greenhouse gas policy, I think, is quite challenging. There have been some recent developments in West Virginia in that regard.

The CHAIRMAN. Dr. Moniz, did you want to make a comment?

Mr. MONIZ. Yes, if I may? Certainly your initial statement fully described you. That is that with current costs of gas, of CCS, getting the marginal kind of CO_2 out of the system is far less expensive just by using gas.

However, on CCS my view remains and I think this is very much in line with what Mr. Biltz said earlier, that well, my premise is I do believe that we are, at some point, going to have a carbon dioxide emission mitigation strategy. I personally have a lot of confidence that Mother Nature will be giving us more and more stern lessons about this. So I believe that it is a public good to prepare the options that we will need for meeting carbon restrictions among those is CCS.

However, as Howard says, you know, today carbon capture and sequestration for a coal power plant is extraordinary expensive mainly because of the carbon capture. So I believe that our plan should be much more to in this decade firmly establish sequestration, the regulatory requirements, the way we manage the infrastructure. What we need to do that is, in my view, get the cheapest source of megatons of CO_2 that we can to have an organized program on sequestration.

That source of CO_2 is a lot less expensive when you get it from somebody like Dow, for example. Because if it's a coal to chemicals plant or an ethanol plant the cost of the CO_2 is dramatically lower than it is from a large power plant. Then at the same time we should be funding what I believe is a lot of innovative technology ideas that can dramatically cut the carbon capture cost, not incrementally. A 20% reduction is not going to change the game for CCS from a large coal plant, but a factor of 2 reduction could do that.

So we need new concepts.

The CHAIRMAN. Thank you very much.

Senator Murkowski.

Senator MURKOWSKI. Just one last question, Mr. Chairman. I want to ask about developments in NGTL's gas to liquids. I think it was you, Dr. Moniz, that said it may be the best pathway to significant market penetration. I think we recognize that we've got this widening price spread between natural gas and oil. As I understand it, it's expected to continue.

Are we doing enough to encourage the necessary development for gas to liquids within what we've got going on right now?

Mr. MONIZ. I'm sure Mr. Biltz would want to add to this. But I would say that right now the market is simply moving that way in terms of where the rigs are, where the action is because the winter production strong NGL content has a much more favorable economics. The Southwestern part of the Marcellus shale is an example where there is some—a lot of opportunity.

There is, in our view, a need however—so suppose one has a lot of GTL development in the Marcellus region. We don't believe we have the infrastructure yet, you know, all the processing infrastructure etcetera. On the other hand we feel that the market will take care of it.

Senator MURKOWSKI. Mr. Biltz.

Mr. BILTZ. Yes. We would agree with that view. We believe the market is treading in that direction. The issues that concern us are around artificial demand, particularly inelastic demand increases.

So for example in the House right now there's a bill, the NAT Gas bill, looking at putting natural gas into vehicles, as was discussed earlier. In principle based on supply on demand may or may not be an issue. But the fundamental concern is there's no counter balance discussion on supply.

So we might choose to legislate demand without increasing the supply to support that. In which case we are back into the position we were in 2005. So our perspective is there's better alternatives. In that particular case the Argon National lab would tell you that you have a 3 times impact from electric vehicles verses a compressed natural gas vehicle.

So look at using the gas into electricity into vehicles makes a lot more sense from an energy policy as a Nation. What we get mostly concerned about the supply, artificial supply. That particular bill, 180 members, roughly in Congress support it, 80 of those members have never voted for a supply option.

So we get concerned about people very focused on increasing inelastic demand without looking to supply the whole balance set off.

Senator MURKOWSKI. I think we worry around here about picking the winners and losers, rather than thinking about the comprehensive enery policy that you talk about. Sometimes we get it right and sometimes we don't get it right.

I know up in Alaska we're looking at how we might be able to utilize gas to liquids. You know, we've got an oil pipeline that's less than half full now. We're trying to figure out how we keep that moving.

So when we talk about the technologies and what is it that we're doing to help advance them, gas to liquids should be part of the discussion, part of that policy debate.

I appreciate the testimony that all 3 of you have given us, and the extensive level of analysis that has gone into the MIT report.

Dr. Gruenspecht, for all that you and the fine folks at EIA do to provide us with the data and the information that we need, we appreciate it.

Thank you, Mr. Biltz as well.

The CHAIRMAN. Let me ask 1 or 2 other questions here.

You know, when we look at our dependence on oil and our lack of adequate progress in reducing that dependence. You know, it's sort of—it's come about because we've had an abundant, relatively cheap source of oil for a very long time. We're now talking about an abundant, relatively cheap source of natural gas for a very long time ahead of us.

I fear that we could see similar consequences in that any serious effort at further development or deployment of renewable energy would be put on the back burner that further efforts at increased energy efficiency would be put on the back burner. Because everybody says, look, we've got plenty of natural gas. It's not very expensive. So let's concentrate on that and back away on these other areas.

Is this a valid concern in your views? Are there policies we need to put in place to guard against this concern?

Any of you? Mr. Biltz, did you have a view on this?

Mr. BILTZ. Yes, we do. You know, I've worked for Dow for well over 30 years now. This is at least the third time I've been told that we have an abundance of natural gas that will solve our problems. It hasn't played out that way in the past couple experiences.

So we would be very concerned about assuming natural gas as a silver bullet. We would want to see policies that help, again, take the broad look across the supply and demand of energy, the energy policy that would help America focus on energy efficiency as well as on developing our other energy supply sources and ultimately moving toward a low transition or transition to a lower carbon economy.

The CHAIRMAN. Dr. Moniz.

Mr. MONIZ. Yes. I certainly think it would be a huge mistake to lose our focus.

First of all on efficiency in our scenarios certainly to meet carbon goals over a multi-decade period, gas is a critical bridge, as we said earlier. But it only works if we have very, very strong demand management. That's actually where it starts. Then comes the gas. So being much more aggressive on the demand side is absolutely critical.

Second, on renewables and I would add nuclear, in particular CCS. The—we also believe that in this carbon context we cannot stop, take a pause, to prepare economic options with essentially zero carbon. We still have many challenges.

Nuclear has obvious challenges, not to mention the recent ones generated with Fukushima. But that's where, in my view, I really believe we should get on with the option of having a look see whether these small, modular reactors do or do not represent a game changer.

On renewables, we need to look also at the whole issue of how do we integrate large scale wind, let's say, with storage, with gas peaking. How do we get a system that allows us to scale up that wind deployment?

To longer term, by the way, I will admit to being very, very bullish on solar energy. I would like to advertise our future of solar energy report that I hope to have in about 6 months.

[Laughter.]

The CHAIRMAN. We will try to have a hearing on that when that comes out.

Dr. Gruenspecht, did you want to make a final statement?

Mr. GRUENSPECHT. All I would say is that all else equal, with lower prices there is a demand response. So to the extent that there are goals related to renewables, related to other technologies, related to the overall level of consumption, more abundant natural gas and lower natural gas prices would tend to make it more necessary, if one wanted to reach those goals, to use other policy instruments.

The CHAIRMAN. So you're saying large quantities of cheap natural gas make it more important that we have policies that drive us to continue with development of some of these alternative——

Mr. GRUENSPECHT. I wouldn't presume to set the goals, but if indeed you have goals in these other areas I think it's fair to say that abundant, low priced, fossil fuels including natural gas make it less likely that you will reach those goals without the type of policies you're talking about.

The CHAIRMAN. I think it's been very useful.

Senator Murkowski, do you have any additional questions?

Senator MURKOWSKI. Very appreciative of the testimony.

The CHAIRMAN. Thank you very much. Thanks for the excellent work that went into the report, Dr. Moniz.

That will conclude our hearing.

[Whereupon, at 12:03 p.m. the hearing was adjourned.]

APPENDIXES

APPENDIX I

Responses to Additional Questions

RESPONSES OF GEORGE BILTZ TO QUESTIONS FROM SENATOR MURKOWSKI

[Natural Gas Vehicles: conditional support or none at all]

Question 1. In your written testimony, you point out that while the study doesn't openly advocate subsidies for natural gas vehicles, it does call for the government to revise its policies related to CNG vehicles in order to lower up-front costs of such vehicles and the necessary infrastructure. From your written remarks I understand that Dow is opposed to such government-provided incentives. I also note that you highlight Chesapeake Energy's recent announcement regarding their intention to invest in natural gas vehicles, as an illustration that government intervention is unnecessary. Is it safe to say that you support CNG vehicles as long as private industry funds them, but not when the government intervenes? How do you feel about gas-to-liquids technology then?

Answer. Dow advocates for policies that advance the competitiveness of US manufacturing. We advocate against policies that would make the US manufacturing sector less competitive. This is why we feel a sense of obligation to raise concerns with government policies or proposed policies that would significantly increase demand for natural gas in sectors that are relatively inelastic (such as the power sector and the transportation sector).

We do not have a bright-line position on government subsidies in general. We are sympathetic to the issue of energy security and of the need for the country to reduce its reliance on foreign oil. We note that there are many different technologies to reduce this dependence on the demand side. CNG vehicles are a part of the equation, as are hybrids, plug-in hybrids, electric vehicles, biofuel-powered vehicles, more efficient gasoline vehicles, etc. Our point in the testimony was that the market is already driving adoption of CNG vehicles, so incentives are unnecessary. In addition to Chesapeake Energy, AT&T, FedEx, UPS and Waste Management are among corporations converting their fleets to CNG because it saves them money.

On the supply side, renewed efforts in exploration and production in areas like the Outer Continental Shelf will also help reduce dependence on foreign energy sources.

Increased focus on energy efficiency should also be a priority for the nation. As we said in the Dow Energy Plan for America, "As a first step in this comprehensive and more sustainable energy policy, we need an accelerated energy efficiency program over the next 10 years."

On gas-to-liquids technology, Dow believes it is proven technology that does not need government incentives to develop further. It is currently being deployed in many regions of the world. If market conditions become favorable, it will also be deployed in the United States.

[Impact of rising natural gas prices on competitiveness]

Question 2. I absolutely agree that natural gas policies should carefully consider the need to preserve and enhance the competitiveness of U.S. manufacturers. With natural gas prices so much lower relative to oil, American chemical manufacturers clearly enjoy a competitive advantage to their foreign counterparts. I wonder how you see this trend playing out in the near to medium term, as demand for natural gas grows in every sector of the economy, especially power generation. How this will impact your competitiveness?

Answer. Assuming moderate demand growth unperturbed by policies that spike demand ahead of supply, we see this favorable trend continuing. We must be mindful of regulatory policies (emissions regulations, for example) that accelerate retirement of coal-based power generation and artificial incentives for CNG vehicles to displace oil as well as regulatory policies that significantly delay or reduce new supplies of natural gas.

We believe the US needs a balanced energy policy that assures a diverse energy mix including coal, nuclear, natural gas and renewables. Natural gas should not be positioned as the nation's only growth fuel.

Provided government policies do not accelerate demand ahead of supply, we see the favorable trend with respect to natural gas continuing in the medium term. Given our outlook, we are beginning to invest for new growth in the United States.

[Fracking chemicals]

Question 3. As a producer of some of the chemicals that are used in the fracking process, generally speaking, what can you tell us about the safety of these chemicals and why are there such concerns about their usage?

Answer. Legitimate concerns have been raised about hydraulic fracturing (also known as hydrofracking) to access unconventional gas reserves and the chemicals used in the process. There's no doubt the vast majority of concern is because fracking is new to the public and there is a lack of information about it. This is why Dow supports disclosure of chemical identity. We believe it should be pursued to the extent possible without compromising true trade secret information and expect it will alleviate concerns about the risk to human health and the environment.

It is not well understood that chemicals in the hydrofracking process make up less than 1 percent of the fluids used. Federal law currently requires companies to report the hazards of components present in formulations >0.1 percent or >1 percent depending on the nature of the hazards. The law further requires that this hazard information is available to employees via Material Safety Data Sheets (MSDS) at all worksites.

Dow believes that, if done in a safe and effective manner, hydrofracking poses little threat to the environment and is essential for the production of natural gas from shale formations.

Dow produces products used in association with hydrofracking, such as biocides for microbial control, which keep water used in the process clean. This enables recycling and prevents the souring of wells, which can cause them to become flammable and explosive. Our biocide products are regulated under the Federal Insecticide, Fungicide and Rodenticide Act (FIFRA) and registered with EPA and with each state where the material will be used. The stringent regulatory requirements are supported by detailed toxicological and environmental fate data which allows selection of proper materials for the given application and region.

In addition to biocides, Dow also produces other products used in hydrofracking. Dow has committed to publishing product safety assessments for all of our products by 2015 and to make this information available on our public website. This information is available at www.dowproductsafety.com

As this debate further develops, we will share chemicals management best practices and provide our feedback on targeted regulations in development to preserve the economical production of energy from unconventional gas resources. Domestic oil and gas production is a necessary part of a balanced energy policy.

RESPONSE OF GEORGE BILTZ TO QUESTION FROM SENATOR CANTWELL

Question 1. Dow Chemical derives a portion of its consumer base from companies involved in Marcellus Shale natural gas extraction. However, your statements in response to the recent Pickens proposal for subsidizing natural gas cars suggest that your company was concerned about the safety and environmental impact of extraction. What are your specific concerns about the safety and environmental impacts of extraction? What would be the appropriate steps to mitigate these safety and environmental concerns?

Answer. Our concern with the Pickens Plan is that it will drive up natural gas demand without assurances on supply. Much has been made of the "Shale Gale," but in fact it has only added 8 Bcf/d in the last five years. The power sector can absorb this growth on its own with retirements of just one third of coal plants 50 years or older.

On extraction, research to date indicates that, if done in a safe, responsible and effective manner, hydrofracking poses little threat to the environment. The process is essential for production of natural gas from shale formations.

Product stewardship of chemicals used in hydrofracking solutions should follow the same product stewardship principles as for other chemical uses. Chemicals should be evaluated according to their risk potential and managed appropriately. The US chemical industry has developed principles on disclosure and the protection of confidential business information (CBI) in evaluating chemicals, and these principles apply equally to chemicals used in hydrofracking.

Dow is committed to transparency regarding the disclosure of the chemical ingredients of hydrofracking solutions, subject to the protection of proprietary information. Dow supports disclosure of constituents of hydrofracking solutions where chemical identity is not proprietary, but not to the proportions used of each component in the solution (except in the case of medical emergencies, where Dow supports disclosure of the chemical identity of proprietary formulas to medical personnel performing professional duties, subject to a signed confidentiality agreement after disclosure). Dow also supports disclosure of chemical identity to workers and employees in appropriate circumstances with a signed confidentiality agreement, and the sharing of CBI with states and tribes, contingent on the recipient's adoption of enforceable CBI standards and procedures that are at least as protective of CBI as those that EPA has adopted and implemented, and subject to a written agreement.States should control reporting requirements and format of reporting and public disclosure. Because local geological, hydrological, geographical and other differences can require the use of different chemicals in hydrofracking solutions, oversight should be handled by states. State governments have the knowledge and experience to oversee hydrofracking in their jurisdictions, and have done so safely for many years.

RESPONSES OF HOWARD GRUENSPECHT TO QUESTIONS FROM SENATOR MURKOWSKI

Question 1. The MIT report asserts that CO_2 emissions price for all fuels without subsidies will maximize the value to society of the large domestic resource base. Do you agree?

Answer. Recent EIA analyses suggest that placing an explicit or implicit price on CO_2 emissions would send a clear signal to all producers and consumers of fossil fuel-based energy to takes steps to reduce their overall energy consumption, switch from carbon intensive fuels to less carbon intensive fuels or carbon-free fuels, or invest in equipment that captures and sequesters the CO_2 emitted from fossil fuel plants. Placing a price on CO_2 would likely lead to increased use of natural gas and reduced use of coal in the near-term, because natural gas is less carbon intensive than coal.

Question 2. What implications does the recent Fukushima tragedy have on the global energy outlook? What fuels will face the most direct impact from fuel switching from nuclear energy in light of the concerns stemming from that tragedy?

Answer. In addition to being a human tragedy, the earthquake and tsunami in Japan also had a significant impact on the country's energy infrastructure. A large number of energy facilities were knocked off line and many remain out of service today. Taking account of both damaged and undamaged nuclear plants that are not currently in use, less than 18 gigawatts (GW) of a total commercial nuclear capacity of 49 GW is currently in operation. In response, Japan has both increased its reliance on other fuels including coal, oil and natural gas, and called upon its people and businesses to conserve electricity.

The longer term impacts of the tragedy will depend on how countries with existing nuclear fleets or planned nuclear additions respond. While a few countries have announced plans to reduce their reliance on nuclear, most with existing or planned nuclear units are carefully reviewing the Fukushima incident to determine if they need to make changes in their nuclear plant construction, operation or regulatory practices. It appears likely that there will be some impact on the projected expansion of global nuclear power generation, but that impact is difficult to quantify at this time. The alternative options to nuclear will vary by country.

RESPONSES OF ERNEST J. MONIZ TO QUESTIONS FROM SENATOR MURKOWSKI

[Technology & resource estimates]

Question 1. In this industry, technology changes so rapidly, that what was considered "cutting edge" two or three years ago is now standard industry practice. With regards to the resource estimates you provide in your report, and particularly the "mean estimate case," are you taking into consideration the most advanced technology available today? Given the work that is being done by the National Petroleum Council, the Potential Gas Committee and others to compile new resource estimates based on today's advanced technologies, why did you chose to base your conclusions off of less recent figures?

Answer. Technological development is an important uncertainty when considering the potential size of the recoverable shale resource. The resource estimates, and associated supply curves (low, medium and high,) used for analysis in the MIT Future of Natural Gas Study were based upon the best geologic data available to the study group during its work, and assuming the use of 2010 drilling and completion technologies. Analysis was also carried out regarding an "advanced technology" scenario, the details of which can be found in Appendix 2C of the report. As to be expected, this advanced technology analysis suggested appreciably larger resources. However, the level of uncertainty surrounding the advanced technology assumptions and the associated resource estimates meant it was not considered suitable for use as the study's "base case." Of course, our economic modeling built upon the shale resource "base case" already showed a major impact in multiple sectors; this would be amplified with a larger modest-price resource.

The current work being undertaken by the National Petroleum Council and the Potential Gas Committee is using data in their contemporary analysis that was not available when the MIT study group was carrying out its work. These data will likely lead to a further increase in estimates of the shale resource size. However, it is important to appreciate that these new estimates still remain subject to significant uncertainty. Furthermore, our work emphasized the importance of treating natural gas resources through supply cost curves; for the short to intermediate term, the issue will be the extent to which new technology extends the resource base at low and modest breakeven prices.

[Global gas market & energy security]

Question 2. In your report you recommend that the U.S. pursue the development of an integrated global gas market, as this would be beneficial to U.S. interests and security, but then say that if this integrated market evolves, the U.S. could become a "substantial net importer of LNG in future decades." It's hard for me to reconcile this—that somehow importing a resource that we can produce at a significant scale here at home makes a lot of sense. Can you explain?

Answer. Indeed, the MIT report recommends the development of an integrated global gas market as it will advance security interests through diversity of supply and resilience to disruption both in the U.S. and its allies. In addition, there is a potential for small natural gas exports from the U.S. in the next decade. We also show that by 2030-2040 relatively cheaper shale resources in the U.S. will be already produced and lower cost suppliers will be competitive again on the U.S. natural gas market (of course, these dates could be shifted later with improvements in shale gas science and technology that expand the modestly priced resource base). The figure below (*Figure 2.10 from the MIT study) provides costs and volumes of natural gas in different regions of the world; while the U.S. has substantial resources at modest breakeven prices, there are other regions with lower cost supplies, regardless of natural gas market structure—but often with great distances to large markets.

By 2030-2040 the U.S. could become a substantial net importer of LNG, but access to relatively cheaper natural gas imports in a truly integrated global gas market would lower natural gas prices for the U.S. consumers, which is beneficial for the U.S. economy. The U.S. will still produce a resource at a significant scale here at home; indeed we find that the lower domestic prices increase domestic demand substantially, so imports do not displace domestic gas on a one-for-one basis. In our scenarios the need for substantial imports will not happen until 2030 or later. We also stress that the path to a global integrated market is far from clear.

The situation for natural gas is quite different from that for oil, where there is already a global market but also non-market cartel forces at work. Recent oil prices have been very high: about three times that for U.S. natural gas on an energy equivalence basis, largely because we have a functioning gas market with gas-on-gas pricing. Given our extreme dependence on oil imports, this has resulted in a roughly $1B/day contribution to the U.S. trade imbalance. However, the oil market is relatively inelastic in that our transportation is almost entirely dependent on oil. In contrast, there is a high degree of substitution possible for gas, especially in the large electricity market, so it is much less likely that an effective cartel could develop to "control" prices.

The U.S. also has unique security responsibilities. The segmented global natural gas markets leave some U.S. allies vulnerable to supply disruptions, such as experienced in Germany not long ago when Russian supplies were interrupted, and this

*All figures have been retained in committee files.

can constrain U.S. foreign policy options for collective action if allies are limited by energy security vulnerabilities. This consideration balances security concerns about imports given our large resource base and the substitution options for natural gas.

["Whether" vs. "How" resources will be developed]

Question 3. In the introduction to your report, you explain that the report sets out to review the extent and cost of shale gas resources, and I couldn't help but notice that you use the word "whether" these supplies can be developed and produced in an environmentally sound manner. I would have thought that we are at the stage of discussing "how" these supplies can be developed in an environmentally sound manner, rather than "whether" they will. Do you question that this is possible? It seemed a bit of a contradiction from your statement that "the environmental impacts of shale gas are challenging but manageable."

Answer. When work commenced in 2008 on the MIT Future of Natural Gas Study a broad set of questions remained open regarding the U.S. shale resource. One of the key questions at that time related to the environmental impacts of shale development, and whether shale gas could be developed in an environmentally sound manner. Over the course of the study, extensive work was carried out on this issue and it was concluded that shale related environmental issues are "challenging but manageable." In other words, it is the Study Group's position that the shale resource can be developed in an environmentally sound manner, assuming rigorous enforcement of best practice regulations and adoption of integrated water plans. Our "challenging but manageable" conclusion was the result of our studies, not an assumption at the outset. Given this, we feel that no contradiction exists.

[Methane hydrates]

Question 4. Your report mentions the possibility of the production of methane hydrates in the out years of the report and recommends that we continue to fund flow testing of well-to-tap hydrates. Coming from Alaska, where we are estimated to have between 560 and 600 trillion cubic feet of methane hydrate onshore and about 32,000 trillion cubic feet offshore—15 percent of the nation's theoretical 200,000 trillion cubic feet of the gas—should we be doing even more to prove the technology to get that energy supply to market in an environmentally sensitive manner?

Answer. Although not currently considered commercially recoverable, methane hydrates do offer the potential of a very large future natural gas resource. However, in order for this potential to be realized a very substantial amount of research and development work needs to occur over the coming years. The MIT study recommends that methane hydrate research currently ongoing should be continued. Areas of focus should include methods for detecting highly concentrated deposits, better resource assessment and longer-term production testing. In terms of support for this work, we believe that additional funding is merited as part of a balanced portfolio that addresses intermediate term unconventional gas opportunities as well (such as the basic science of shale formations and production). As pointed out in the report, there are numerous RD&D opportunities to address key objectives for natural gas supply, delivery, and use, and a renewed DOE program is appropriate for much of this agenda.

RESPONSES OF ERNEST J. MONIZ TO QUESTIONS FROM SENATOR CANTWELL

Question 1. The newly-released MIT natural gas study found that methanol produced from domestic natural gas resources was cost-competitive as a transportation fuel even under the assumption of a relatively low $2.30 per gallon gasoline price and natural gas prices as high as $8 per MMBtu. What would you estimate to be the economic advantages (vs. petroleum-derived gasoline, corn-based ethanol, and ethanol imports) of methanol at today's gasoline prices, which are close to $4.00 per gallon?

Answer. The cost of producing methanol (natural gas cost and conversion) in $ per gasoline gallon equivalent (gge) in the MIT report should be compared to the cost of producing gasoline (oil cost and refining). For gasoline at a retail price of $4.00 per gallon, we take an illustrative production cost around $3.10/gallon. For $6/MMBtu natural gas, the illustrative production cost in the report was $1.60/gge. In this case the economic advantage of methanol would be around $1.50/gge on a production cost basis. Since the cost of transportation of methanol is around $ 0.10/gge higher than gasoline, the economic advantage relative to gasoline would be around $1.40/gge.

The present cost of corn based ethanol is around $2.75 per gallon of ethanol, corresponding to around $ 3.90/gge (the ethanol futures price has risen dramatically in the last year). In this case the economic advantage of $1.60 /gge methanol (from $6/MMBTu gas) is around $2.30/gge. Even with an ethanol price of about $1.85, which is more typical of the price a year ago, there would still be about a $1/gge advantage to methanol from $6/MMBtu gas (and today's price is close to $4/MMBtu). The methanol price advantage is quite robust at this time.

It is difficult to make a comparison to ethanol imports.

Question 2. The MIT natural gas study advocates the adoption of a federal open fuel standard requiring auto makers to produce light-duty vehicles with tri-flex-fuel (gasoline, ethanol, and methanol) capability, noting that the production cost associated with expansion to tri-flex-fuel capability would be around $100 per vehicle. How was the incremental cost of making a vehicle tri-flex-fuel capable derived or sourced and is the incremental cost higher or lower than the traditional bi-fuel (E85) capable flex fuel vehicle? Would this incremental cost allow the U.S. light-duty fleet to operate on high-concentration blends of methanol (e.g., M70) and ethanol (E85), without degradation of engine components or lower vehicle performance? Do you believe there any technological challenges that might impede the use of high-concentration methanol blends in U.S. light-duty vehicles? Has MIT reviewed other considerations of consumer acceptance that might impede the adoption of tri-flex vehicles?

Answer. The incremental cost of $100-200 for a tri-flex fuel vehicle that was given in the MIT report is relative to the present ethanol -gasoline flex fuel vehicle. The main component in this extra cost was an alcohol sensor that is required for control of the air/fuel ratio in a tri-flex fuel vehicle.

Yes this would allow high concentrations of methanol and ethanol. In fact, vehicle performance and/or efficiency can be higher if advantage is taken of the higher octane of methanol relative to gasoline. However, for a given size fuel tank vehicle range is reduced when using M70 to around two thirds of the range when using gasoline. The consumer has choices, such as using less alcohol when driving long distances, assuming that the fueling infrastructure is sufficiently flexible.

A 2010 MIT report by Bromberg and Cheng (PSFC/RR-10-12) concluded that the technical challenges could be addressed at an incremental vehicle cost of the scale noted above. Continuing engineering developments will be needed at the auto companies and research laboratories, depending especially on how future emissions requirements (e.g. for hydrocarbons) are set; very stringent emissions requirements could well raise the incremental cost to enable a wide range of fuel mixtures. Of course, environmental precautions are also needed in the transportation of the methanol (e.g. preventing dispersion in surface waters), as is the case for all liquid fuels.

We have not reviewed consumer acceptance considerations.

Question 3. The MIT Future of Natural Gas study affirms that methanol infrastructure is needed for penetration of the fuel into commercial transportation. What are the estimated installation costs for new methanol tank and pump apparatus, and what are the estimated costs to upgrade existing gasoline tank and pump apparatus? How do these costs compare with ethanol and gasoline tank and pump apparatus? What policy incentives do you foresee as necessary to spur the development of a national refueling infrastructure to support a tri-flex-fuel U.S. passenger fleet?

Answer. We estimate the installation costs for providing new tank and pump apparatus for methanol fueling to be in the $ 60,000-$70,000 range. The cost is similar to ethanol tank and pump costs and modestly higher than gasoline tank and pump costs.

The most important policy incentive would be clarity in moving towards tri-flex-fuel capability in a large part of the light duty vehicle fleet (for reasons discussed below). Clearly other incentives could include subsidies for methanol fueling infrastructure, similar to that for ethanol.

Question 4. What role would the adoption of a tri-flex-fuel open fuel standard play in breaking the petroleum monopoly in the U.S. transportation sector?

Answer. A tri-flex fuel vehicle standard addresses two long-term and related US energy concerns: global oil prices "controlled" by a cartel; and the lack of fuel alternatives in the US transportation sector.

OPEC effectively controls oil prices by increasing or decreasing supplies and controlling the amount of surplus oil productive capacity. Also, oil based products meet 97% of US transportation needs. Artificial constraints on supply plus the lack of transportation fuel alternatives and the associated price inelasticity, places American consumers and our transportation system at risk, where even minor market perturbations result in price volatility and higher prices.

An open fuel standard, by requiring engines that could run on three liquid fuels—gasoline, ethanol and methanol—would promote competition and a type of arbitrage between fuels, putting downward pressures on prices and reducing opportunities for cartel behaviors. Importantly, these fuels would be derived from three major feedstocks: petroleum, biomass, natural gas. We have recently seen oil prices and corn ethanol futures rise considerably, while natural gas prices have dropped significantly. In the future, this pattern could be different, so consumer flexibility is critical. Furthermore, cellulosic ethanol and biomass-derived methanol provide pathways to carbon dioxide emissions reductions as well.

An open fuel standard would not dictate fuel or technology choice; this would still reside with the consumer. Indeed it would enable fuel choice options that currently do not widely exist.

The cost of creating this option is modest, in the $100-$200 range per vehicle. There are also additional infrastructure needs; we do however have a growing experience base with ethanol distribution that could inform the methanol option. It is worth noting that we have changed our retail fuelling infrastructures successfully in the recent past to respond to policies and mandates, most notably by adding specialized pumps for unleaded fuels and E85.

Question 5. Given current U.S. natural gas resources, what share of the nation's transportation fuel demand could be satisfied with domestically-produced high-concentration methanol blends such as M70? What would be the implications of this level of penetration for U.S. greenhouse gas emissions?

Answer. The ultimate limitation could be how much natural gas production can be increased for this new market. Around 3 tcf/yr of natural gas must be converted into methanol in order to replace 1 million barrels/day of oil. Thus, about 14% of today's U.S. natural gas consumption would displace about 9% of vehicular transportation fuel (gasoline plus diesel). In addition to replacement of gasoline in light duty vehicles, natural gas derived methanol could also be used as in high efficiency spark ignition engines in heavy duty vehicles as a replacement for diesel fuel. This substitution of a natural gas derived liquid fuel for diesel fuel is an alternative to the use of LNG for heavy duty vehicles.

US greenhouse gas emissions would essentially be unchanged unless carbon dioxide was captured during the natural gas to methanol conversion process and then sequestered, reducing greenhouse gas emissions by 20-30%.

Question 6. The MIT natural gas study states that when conversion energy losses are taken into account, greenhouse gas emissions from natural gas-derived methanol are slightly lower than those from gasoline use. Yet, the study then notes that methanol's "GHG emissions could be somewhat higher if methane emissions are included." (p. 133) Would you please explain in greater detail the actual or potential sources of the methane emissions to which the study refers? Would these emissions be greater or smaller depending on the method of natural gas production (e.g. conventional production versus fracturing)? How significantly could production-related methane emissions alter the GHG profile of methanol relative to gasoline?

Answer. When comparing GHG emissions for different energy sources, attention should be paid to the entire system. In particular, the potential for leakage of methane in the production, treatment, and distribution of fossil fuels has an effect on the total GHG impact of each fuel type. The EPA is revisiting methane emissions factors. A recent focus has been on fugitive emissions from the production of natural gas at the well. The MIT report includes methane leakage in its system-wide modeling studies but does not attempt a detailed accounting for the analysis of specific end uses. The statement quoted above was a reference to potential impact. However, the report urges the EPA and DOE to co-lead a new effort to review, and update as appropriate, the methane emissions factors associated with fossil fuel production, conversion, transportation, and use, seeking broad-based consensus on the appropriate methodology. The analysis should rely on data and should reflect the potential for cost-effective actions to prevent fugitive emissions and venting of methane.

We do not expect a significant increase in the GHG profile of natural gas derived methanol relative to gasoline. The recommended study would provide a quantitative measure. However, there are also opportunities to reduce system emissions further by improving the natural gas to methanol conversion efficiency and by capturing the higher engine efficiency attainable with methanol.

Question 7. Recent reports from Cornell University, Duke University, and the U.S. Forest Service have been published regarding the general environmental impacts of hydraulic fracturing. The Cornell study stated that natural gas extraction contributed to greater greenhouse gas emissions than previously thought. The Duke study found that there was a correlation between methane levels and distance to natural gas drilling sites. The Forest Service found immediate vegetation die-off possibly as a result of hydraulic fracturing wastewater disposal. How would these current reports alter your conclusions in the frequency and type of environmental impacts of hydraulic fracturing? In particular, regarding the possible greater greenhouse gas footprint of natural gas extracted from shale.

Answer. While they appeared recently, the Cornell and Duke University studies were available to us prior to the completion of the report and so our conclusions reflect our consideration of these studies. We are not aware of the specifics of the U.S. Forest Service study.

Our gas study team reviewed the environmental issues that have been associated with hydraulic fracturing. *Figure 1 is taken from the study (Table 2E.1) and it shows that on-site spills and inappropriate offsite water disposal account for 33 and 9 percent, respectively of the widely-reported environmental incidents over a five year period. While the study identifies the types of additives used as fracturing fluids and showed that many are chemicals commonly used in households, even some of these regularly used chemicals can be toxic to plants at high levels, so an incident of vegetation die-off is possible from improper disposal of hydraulic fracturing wastewater. These potential environmental risks were considered as we developed recommendations, leading to one of four highlighted recommendations on gas supply:

> A concerted coordinated effort by industry and government, both state and Federal, should be organized so as to minimize the environmental impacts of shale gas development through both research and regulation. Transparency is key, both for fracturing operations and for water management. Better communication of oil- and gas-field best practices should be facilitated. Integrated regional water usage and disposal plans and disclosure of hydraulic fracture fluid components should be required.

In particular, the study recommended that the constituents of fracturing fluids should be publicly available, allowing research to investigate potential hazards and for regulation to limit use of chemicals that were found to be hazardous.

Figure 1 also shows that half of the widely-reported environmental incidents were related to the contamination of groundwater with natural gas, as the result of drilling operations. Most frequently, this appears to be related to inadequate cementing of casing into wellbores. The Duke University study was carefully done and its findings reiterate concerns about the care with which gas drilling has been conducted in some cases. Because the study was not able to sample water in wells before and after the drilling operation, the finding leaves open the possibility that the gas was present in these wells prior to the drilling operation. However, the strong statistical relationship between high levels of gas in water wells close to the drilling operation as compared with those some distance away strongly suggests that the drilling operation was responsible. The Duke study concluded that because the fracturing occurs thousands of feet below near-surface aquifers it seems highly unlikely that fracturing itself leads to methane contamination of groundwater. It also concluded, as do we, that the likely source of methane is poor construction of the well casings. The MIT study included a diagram and steps for proper well construction, repeated here as Figure 2 (Fig. 2.18 of the report) and concludes that proper regulation, inspection, and management of the drilling operation could likely minimize this risk. That is, properly implemented cementing should prevent methane leaks to groundwater. Poor construction of casings would also lead to methane contamination of water from conventional gas production and so this does not raise new issues that just apply to shale gas or to hydraulic fracturing.

These specific issues associated with methane contamination were also behind the major recommendation already repeated above. Given the one limitation of the Duke University study, the inability to sample prior to drilling, in the future any wells or shallow aquifers near a drilling site should be sampled both prior to when the drilling operation commences and then after to determine more conclusively the cause and effect relationship. Such sampling and testing might be carried out by an independent party.

We also had the benefit of having access to the Cornell University study prior to the completion of our report. That study's lifecycle greenhouse gas emissions associated with the production and use of natural gas appear to us to be substantially too high. This is an important issue. However, cited material in the Cornell study did not contain details at the depth needed to reproduce the calculations or directly evaluate them.

A major conclusion of our study is that natural gas can be a very effective near to mid-term solution for reducing greenhouse gas emissions, principally by substituting for coal in electricity generation. It is generally recognized that combustion of natural gas for power generation is only ° or less GHG-intensive than producing power from coal using conventional methods that do not capture CO_2. The Cornell University study produced calculations that suggested the exact opposite, that power generation from natural gas might be twice as GHG-intensive as coal genera-

* All figures have been retained in committee files.

tion. Consequently, a group of MIT faculty (John Reilly, Henry Jacoby, Ron Prinn, Dick Schmalensee), some part of the Natural Gas study and some not, collaborated on a review of the Cornell study. Combined with the assumption of very high fugitive emissions in shale gas production, the MIT faculty group trace the extreme conclusion of the Cornell study on the climate impacts of natural gas versus coal to: (1) the use of 20-year Global Warming Potential (GWP) indices when authoritative scientific and regulatory bodies have settled on 100-year GWPs, the result being to dramatically elevate the climate effects of methane leakage versus carbon dioxide from fossil fuel combustion; and (2) using a very low natural gas-to-electricity conversion efficiency, that associated with gas peaking plants, when any replacement of base load coal power generation would almost certainly use high efficiency combined cycle plants to replace very inefficient old coal plants (as is happening already with no carbon policy!). Neither assumption is in our view appropriate. Replacing them with accepted ones restored the conclusion that gas is about ° as GHG-intensive as coal, even with high estimates of gas leakage.

Nevertheless, the issue of quantifying fugitive methane emissions for fossil fuel production, conversion, transportation, and end use should be revisited. This led us to include, in our study, the following major recommendation:

> The EPA and the U.S. Department of Energy (DOE) should co-lead a new effort to review, and update as appropriate, the methane emission factors associated with natural gas production, transmission, storage and distribution. The review should have broad-based stakeholder involvement and should seek to reach a consensus on the appropriate methodology for estimating methane emissions rates. The analysis should, to the extent possible: (a) reflect actual emissions measurements; (b) address fugitive emissions for coal and oil as well as natural gas; and (c) reflect the potential for cost-effective actions to prevent fugitive emissions and venting of methane.

Another important factor is that methane emissions at the wellhead can be captured for economic benefit. Indeed, a GHG cap and trade policy would provide further economic incentive. This is in contrast to post-combustion carbon dioxide capture and sequestration, which is a very expensive proposition than can be justified only with a high carbon dioxide emissions price (or equivalent regulation). Our report shows that, together with demand management, substitution of natural gas for coal is the most cost effective near-term approach to reducing carbon dioxide emissions.

RESPONSE OF ERNEST J. MONIZ TO QUESTION FROM SENATOR UDALL

Question 1. Your report has several suggestions for addressing the risks of shale gas drilling, including following best practices for casing and cementing. Do you think current best practices for cementing and casing are sufficient to protect groundwater from the materials in the well bore, or is more R&D needed to improve industry methods in this area?

Answer. We believe that the application of current best practice to casing and cementing is the minimum level of regulation necessary to address the environmental issues associated with shale development. Additional research and development would be appropriate given the importance of the technology, and much of this will go on in industry. However, public funding of more basic research, such as developing novel materials and advanced sensors to further enhance the safety and reliability of drilling operations, would also be appropriate.

RESPONSES OF ERNEST J. MONIZ TO QUESTIONS FROM SENATOR SHAHEEN

Question 1. The recent MIT report discusses the importance of energy efficiency and makes recommendations on how efficiency should be deployed to balance energy demand in the future. Energy efficiency is the cheapest, fastest way to address our energy needs, and it must play a central role in moving us to a clean energy future. Could you discuss the interplay between the development of a domestic natural gas supply and the increased use of combined heat and power (CHP) in industry and in the power sector?

Answer. We see a strong interplay between the current outlook for natural gas supplies and the potential for increased use of CHP in large scale applications. CHP systems have very high overall energy efficiency levels (in the range of 60% up to 90% in some cases). Natural gas combustion turbines, coupled with waste heat recovery systems, are the leading technology for larger scale CHP systems, and thus represent an opportunity for increased demand for natural gas for this application. The combination of current supply and price for natural gas and relatively low capital and operating costs for natural gas based CHP systems make natural gas based CHP an attractive alternative for many industrial facilities. Industrial CHP systems can be sized to meet heat loads within the plant. Electrical supply and demand levels within the industrial facility can be balanced with the grid. For example, many local electricity distributors offer programs for the purchase of excess electricity generation from industrial CHP facilities. The report notes the recent Energy Information Administration Annual Energy Outlook 2011 projection of an increase of 181 percent in electricity generated from end-user CHP systems by 2035. This would imply an increase in natural gas use of 1.7 Tcf per year by 2035.

Question 2. A recent report by Black and Veatch (a global engineering, construction and consulting firm) estimated that 54,000 MW (or 16% of the existing coal-fired power generation fleet) will likely be retired in the near future. There are a variety of factors for these retirements, including age and the economics of the plants as well as pending EPA regulations to reduce smog and hazardous air pollutants. Coming from a downwind state, these are important regulations to protect the health of children and at-risk populations. But in all likelihood we are looking at a time of tremendous transition in our power sector. What role do you see for natural gas and greater use of CHP in this transition of our power sector?

Answer. We see a significant role for natural gas in electricity generation in just about any scenario, not only to reduce emissions of conventional pollutants but also as a measure to achieve significant reductions in greenhouse gas (GHG) emissions in the power generation sector. Our study analyzed this issue from several different perspectives. In Chapter 4 of the report, we present an analysis of near term opportunities achieving emissions reductions through increased utilization of existing natural gas combined cycle generation capacity to displace existing coal generation capacity. Our analysis showed that there is sufficient surplus NGCC capacity to displace roughly one-third of U.S. coal generation, an amount approximately twice as large as the level of retirements projected by Black and Veatch. The analysis indicated that, on a national basis, the full utilization of existing NGCC would reduce NOx and mercury emissions by about one-third and CO_2 emissions by about 20 percent, while increasing demand for natural gas by about 4 Tcf per year. We concluded that this represents a low cost solution to achieving significant emissions reductions, without the need for significant capital investment in new electricity generation capacity. However, we point out that these are national results, and that analysis in greater geographical detail is needed in order to validate the actual displacement by region and also to identify with higher resolution constraints due to the existing transmission infrastructure and to the needs of balancing supply and demand.

We also performed longer-term modeling of the electricity sector using the MIT Emissions Prediction and Policy Analysis (EPPA) model. We used this model to better understand the implications of policies for achieving significant reductions in GHG emissions in the U.S. economy. Our base GHG emission reduction scenario was a price case where a 50 percent economy-wide GHG emissions reduction is achieved by 2050 through the application of a price on carbon. In this case, coal generation completely phased out by 2035, while the level of natural gas generation tripled. Subsequently however, natural gas also began to decline due to increasing carbon prices, transitioning to a carbon-free electricity sector. Coal and eventually natural gas need more economic CCS in order to compete with nuclear and renewables when the emissions price is very high.

Question 3. Your report finds that CHP isn't currently viable at residential scales. What steps can we take to expand CHP in this sector? Do we need more research and development?

Answer. Our analysis of residential CHP use indicated that the economics of CHP use was strongly dependent upon the matching of heat and power loads with the heat and power output levels (or heat to power ratios) from various CHP technologies. We modeled a residential case study of the New England region that entails large seasonal variation in heat and power loads, with a large power load in summer (for air conditioning) and a large heat load in the winter season. Deployment of existing engine-based CHP technologies, which have relatively high heat-to-power ratios, was not economic, even in cases where the CHP system was sized to meet the winter peak heat load. We concluded that efforts to reduce the capital cost of residential CHP technologies, as well as develop technologies with lower heat to power ratios, were needed in order to make residential CHP systems more competitive.

Our analysis clearly identifies the need for additional R&D on smaller scale CHP technologies. A quote from Chapter 8 (p. 165) sums this best:

> . . . micro-CHP (kilowatt scale) will need a substantial breakthrough to become economic. Micro-CHP technologies with low heat-to-power ratios

will yield greater benefits for many regions, and this suggests sustained research into kW-scale high-temperature, natural gas fuel cells.”

APPENDIX II

Additional Material Submitted for the Record

DEPARTMENT OF ENERGY,
Washington, DC, July 19, 2011.

Hon. JEFF BINGAMAN,
Chairman, Committee on Energy and Natural Resources, U. S. Senate, Washington, DC.

DEAR MR. CHAIRMAN:

As promised in response to the questions this morning concerning the recent New York Times article relating to EIA's shale gas assessment, I am enclosing the complete response EIA provided to a letter from Representative Edward J. Markey, Ranking Member of the House Committee on Natural Resources.

Please do not hesitate to contact me should you have any questions. Your staff may also contact John Conti, Assistant Administrator for Energy Analysis at 202-586-2222.

SINCERELY,
HOWARD K. GRUENSPECHT, ACTING ADMINISTRATOR,
Energy Information Administration.

Enclosure.

DEPARTMENT OF ENERGY
Washington, DC, July 8, 2011.

Hon. EDWARD J. MARKEY,
Ranking Member, Committee on Natural Resources, U.S. House of Representatives, Washington, DC.

DEAR REPRESENTATIVE MARKEY:

This is in response to your letter of June 27, 2011 concerning the data and methodology used by the U.S. Energy Information Administration (EIA) to compile estimates of shale gas reserves and resources. Your letter cites a New York Times (NYT) article that EIA believes unfairly characterizes the integrity of our shale gas estimates. We are glad to have the chance to address your concerns and have sought to provide you with responsive information promptly.

The enclosure provides responses to the questions raised in your letter and additional materials that bear on your inquiry, including EIA's response to a pre-publication inquiry from the author of the NYT article cited in your letter and more complete copies of selectively redacted e-mails that were posted on the NYT website.

As noted in your letter, the estimate of shale gas resources (excluding proved reserves) in EIA's Annual Energy Outlook 2011 (AE02011) is 827 trillion cubic feet. An additional 35 trillion cubic feet of proved reserves brings the total estimate of technically recoverable shale gas resources in AE02011 to 862 trillion cubic feet.

EIA staff and management have carefully reviewed the NYT article and have found nothing that causes us any concern regarding the methodology, data, and analysis that underlies the estimates of shale gas in AE02011. In fact, the AE02011 Issues in Focus section includes a dEIAiled discussion that addresses both the upside and downside uncertainties surrounding shale gas.

Hopefully, the enclosed information will provide you with useful insight into the data and methodology that underlie EIA's shale gas estimates. We would also welcome the opportunity to brief you and your staff on our shale gas estimates and any issues raised by the NYT article.

Please do not hesitate to contact me if we can be of further assistance. Your staff may also contact John Conti, Assistant Administrator for Energy Analysis, at 202-586-2222.

SINCERELY,
HOWARD K.. GRUENSPECHT, ACTING ADMINISTRATOR,
U.S. Energy Information Administration.

Responses to questions raised in a June 27, 2011 letter from Representative Edward J. Markey, Ranking Member, House committee on Natural Resources to Richard G. Newell, Administrator, energy Information Administration

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Question 1. Please provide the methodology and all supporting materials behind EIA's estimate of U.S. natural gas resources or reserves used in the AE02011. Has the methodology used to estimate U.S. natural gas resources or reserves changed from previous estimates? If so, how and why was the methodology changed?

Answer. EIA continues to use the methodology instituted over a decade ago tc estimate oil and natural gas resources, including shale gas resources, for the Annual Energy Outlook (AEO) energy projections. EIA's oil and gas resource estimates are updated annually as new information becomes available. In recent years, the AEO natural gas resource estimates have increased substantially as extensive shale gas drilling and production indicated the widespread economic viability of shale gas production in a growing number of shale formations, particularly in the Marcellus and Haynesville shale formations.[1]

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*Materials to the appendices have been retained in committee files.

[1] The Annual Energy Outlook 2011 oil and natural gas resource estimates and model assumptions are available on the EU website at http:/Avww.eia.govi/forecasts/aeo/assumntions/oi____gas,pdf. (See attached Appendix A.)

EIA's domestic oil and natural gas technically recoverable resources[2] consist of proved reserves,[3] inferred reserves,[4] and undiscovered technically recoverable resourees.[5] EIA resource assumptions used in the AEO are based on estimates of technically recoverable resources from the United States Geological Survey (USGS) and the Bureau of Ocean Energy Management Regulation and Enforcement (BOEMRE). EIA then makes adjustments to add frontier plays that have not been quantitatively assessed and for those plays currently under development where the latest available USGS assessment was clearly out-of-date.

Over the past decade, several important EIA adjustments have involved continuous-type resources of oil or natural gas that are trapped within the source rock where they were created.[6] For example, for AE02007, EIA adopted in 2006 an estimate of 3.60 billion barrels of oil resources for the Bakken formation, significantly higher than the latest USGS resource estimate at that time, which had been based on an assessment made in 1995. Subsequently, in 2008, USGS issued an updated assessment that estimated Bakken mean technically recoverable oil resources at 3.65 billion barrels.[7]

Turning to shale gas, the rapid increase in development activity and production over the past several years has created situations where the latest available USGS assessment was clearly out of date. For example, the last USGS assessment of the Marcellus shale was published in February 2003 for 2002, with the mean value of technically recoverable resources estimated at 1.9 trillion cubic feet.[8] Subsequent to the USGS assessment of the Marcellus, it became apparent that the application of horizontal drilling and hydraulic fracturing technologies would result in much higher resource recovery rates. The EIA estimates that Marcellus shale gas production in 2010 was about 400 billion cubic feet, which would have been impossible if the Marcellus resource were constrained to the volume estimated by the USGS in 2002.

The EIA estimates of shale gas resources within a specific shale formation use an assessment methodology for continuous-type resources originally developed by the USGS[9]. A shale formation's gas resources are calculated fora particular subregion and sub-play using the following equation:

Resources = (Play/sub-play area in square miles) x
(Estimated ultimate gas recovery per well EEUR], in billion cubic feet [Bcfl per well) x
(Number of wells per square mile) x
(Play probability) x
(USGS factor)

[2] Technically recoverable resources are resources in accumulations producible using current recovery technology but without reference to economic profitability.

[3] Proved reserves are the estimated quantities that analysis of geologic and engineering data demonstrates with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

[4] Inferred reserves are that part of expected ultimate recovery from known fields in excess of cumulative production and current reserves.

[5] Undiscovered resources are located outside oil and gas fields in which the presence of resources has been confirmed by exploratory drilling; they include resources from undiscovered pools within confirmed fields when they occur as unrelated accumulations controlled by distinctly separate structural features or stratigraphic conditions.

[6] Conventional oil and gas resources, which accounted for virtually all production prior to 1990, are hydrocarbons that have migrated from their source rock and accumulated in a reservoir where they are trapped by impermeable cap or seal.

[7] U.S. Geological Survey, Assessment of Undiscovered oil and Gas Resources of the Williston Basin Province of North Dakota. Montanoa and South Dakota, 2008, Fact Sheet 2008-3092, November 2008. (See attached Appendix B.)

[8] U.S. Geological Survey, Assessment of Undiscovered Oil and Gas Resources of the Appalachian Basin Province, 2002, USGS Fact Sheet FS-009-03, February 2003, Table 1, page 2. (See attached Appendix C.)

[9] The earliest USGS publications on this methodology were published before 2000. The latest version of the USGS methodology is provided in the following USGS publication entitled: Improved USGS Methodology for Assessing Continuous Petroleum Resources, Data Series 587, Version 1, 2010. (See attached Appendix D.)

As discussed in more detail below, EIA's shale gas resource assessment methodology is intended to be relatively conservative, taking into consideration the variation in shale gas well productivity within core and non-core subregions of a play and by assigning a "play probability" and a "USGS factor" that significantly reduces the shale gas resource estimates.

The estimate of Marcellus shale gas resources used in AE02011 illustrates the application of the assessment approach outlined above. Because the Marcellus shale is large in extent, covering about 95,000 square miles,[10] the Marcellus shale gas play is divided into seven subregions,[11] with each subregion having three distinct subregions' shale gas well recovery characteristics to capture the variability in production and resource circumstances within a subregion.

The Marcellus sub-plays have the following shale gas well recovery characteristics over the life of the well for the core and undeveloped (non-core) subregions:

1. The core subregion encompasses 10,622 square miles of Pennsylvania and West Virginia and is subdivided into 3 productivity and resources levels:

- With 30% of the core region having an estimated ultimate recovery (EUR) of 4.66 Bcf/well,
- With 30% of the core region having an EUR of 3.50 Bcf/well,
- With 40% of the core region having an EUR of 2.63 Bcf/well.

2. The 6 undeveloped (non-core) subregions encompass 84,271 square miles in Maryland, New York, Ohio, Pennsylvania, Virginia, and West Virginia, with this region further subdivided into 3 productivity and resources levels:

- With 30% of the non-core region having an EUR of 1.53 Bcf/well,
- With 30% of the non-core region having an EUR of 1.15 Bcf/well,
- With 40% of the non-core region having an EUR of 0.86 Bcf/well.

The EIA uses a variety of public data sources to estimate Marcellus shale gas production decline curves and EURs, including HPDI, LLC well-specific production data.

In each Marcellus subregion, shale gas well spacing is assumed to be 8 wells per square mile, which is 80 acres per well and typical for most shale gas plays.

Given that large portions of the non-core Marcellus have not been production tested, the EIA assessment methodology applies a "play probability" that represents the possibility that some portion of the Marcellus could be noneconomic to develop. The play probability for the Marcellus play is set at 70 percent, which means that 30 percent of the play area is assumed to be uneconomic based on well productivity and EUR considerations. A low well EUR could be due to some or all of the following attributes: the formation is too thin or too close to the surface, low porosity, low pore pressure, high clay content, low carbon content, low absorbed gas volume, and/or low thermal maturation.

The EIA shale gas resource assessment also applies an additional multiplicative factor to reduce resources based on the USGS assessment methodology for "basin continuous" gas formations, which classifies technically recoverable resources as those that can be expected to be potentially added to reserves over a 30-year period.[12] The "USGS factor" used to make this adjustment recognizes that over a 30-year period only some fraction of the technically recoverable resources are likely to be developed due to a number of constraints, including domestic gas consumption requirements, drilling rig availability, sufficiently high gas prices, the availability of producer cash flow and capital funding, and the development of gas processing and pipeline infrastructure. The core Marcellus region is assumed to have a 60 percent USGS factor, and the non-core region is assumed to be a 30 percent USGS factor.

The EIA shale gas resource assessment methodology also takes into consideration natural gas that has been produced or booked as proven :reserves. Consequently, with all else remaining the same over the long term, the Marcellus shale gas re-

[10] The square mileage figure used in EIA's Marcellus shale gas resource estimation is 94,893 square miles.

[11] The Marcellus subregions are as follows: 1) active (aka. core region) region in PA & WV, 2 undeveloped region in MD, 3) undeveloped in NY, 4) undeveloped in OH, 5) undeveloped in PA, 6) undeveloped in VA, and 7) undeveloped in WV.

[12] U.S. Geological Survey, Analytic Resource Assessment Method for Continuous-Type Petroleum Accumulations—The ACCESS Assessment Method, Chapter 6 of Total Petroleum System and Assessment of Coalbed Gas in the Powder River Basin Province Wyoming and Montana, USGS Powder River Basin Province Assessment Team, U.S. Geological Survey Digital Data Series DDS-69-C, 2004, page 1. (See attached Appendix E.)

source volumes would decline as these resources are booked as proven reserves and subsequently produced.

Moving beyond EIA's assessment methodology and its application to the development of updated shale gas resource estimates for AE02011, it should be noted that EIA's oil and natural gas resource estimates undergo continuous modification and improvement based on new information regarding drilling and production technologies, and the ability to produce oil and natural gas resources using those technologies. However, the ultimate cumulative productive capability of any particular shale gas well or set of wells cannot be fully ascertained until those wells are plugged and abandoned.

Finally, it should be noted that EIA oil and natural gas resource assessments are not performed in a vacuum. EIA is constantly comparing its estimates with those of other groups, such as the USGS, the BOEMRE, IHS-CERA, the National Petroleum Council (NPC), and the Potential Gas Committee, when updates and revisions are made available by these groups. Furthermore, the EIA conducts open and public workshops in which representatives of the USGS, the BOEMRE, and other experts are invited to critique both the EIA resource assessment methodology and resource estimates. The last such workshop was held on April 27, 2011 after the conclusion of the EIA Energy Conference.

Question 2. Please list any outside contractors used in formulating EIA's estimate of natural gas reserves used in the AE02011; the criteria used for selecting those specific outside contractors; all correspondence (including reports, emails, memos, phone or meeting minutes or other materials) between EIA staff and any outside contractors, natural gas industry representatives or members of academic institutions regarding estimates of U.S. natural gas reserves; all internal EIA staff correspondence (including reports, emails, memos, phone or meeting minutes or other materials) relating to uncertainties in estimates of U.S. natural gas reserves.

Answer. EIA utilizes a multiple award, Indefinite Delivery Indefinite Quantity procurement vehicle (EOP 3) to obtain the vast majority of its contractor support services, including those related to producing the estimates of natural gas reserves in the AE02011. Task Order Contracts are then issued on a competitive baths, amongst the EOP 3 Multiple Award Coneract winning vendor teams. Science Applications International Corporation (SAIC) was awarded two task orders under EOP 3 to support EIA's modeling and forecasting activities that, among other requirementsaincluded expertise pertaining to natural gas resources. As part of its effort, SAIC utilized a team of subcontractors to address the broad spectrum of modeling and forecasting requirements that feeds into the AEO production process. The subcontractor that specifically contributed to the natural gas resource estimates was INTEK, Inc.

SAIC was awarded a contract under EDP 3 by demonstrating its capability to meet a broad array of technical support requirements with respect to the following selection criteria:

- Business Management Approach
- Technical Approach
- Past Performance
- Corporate Experience

By virtue of its EOP 3 contract award, SAIC was eligible to bid on individual task orders, including the two technical support tasks referenced above. Task order award criteria, standardized across EIA tasks, are as follows:

- Criterion 1: Technical Proposal
  - —la: Business Management Approach
    - —Task Management Plan
    - —Staffing Plan
    - —Quality Assurance Plan
    - —Risk Management Plan
    - —Transition Plan
  - —lb:Technical Approach
  - —Criterion 2: Experience
  - —Criterion 3: Evaluation of Cost

SA1C was selected because it represented the best value to the government based on the totality of its task proposals rather than being based solely on the presence of a particular subcontractor(s), as the natural gas resource estimates represented only a portion of the overall support needs addressed by these task orders.

Question 3. Please provide the methodology and all supporting materials behind EIA's estimate of future U.S. natural gas production, in particular production of shale gas. Has the methodology used to project future U.S. natural gas production changed from previous estimates? If so, how and why has that methodology changed?

Answer. The basic methodology used in the Oil and Gas Supply Module (OGSM) of the National Energy Modeling System underlying the 2010 and 2011 Annual Energy Outlooks is unchanged. The majority of the changes between the AE02010 and AE02011 reflects updates/revisions to input data and not structural methodological revisions. The major changes include:

- Texas Railroad Commission District 5 is included in the Southwest region instead of the Gulf Coast region.
- Re-estimation of Lower 48 States onshore exploration and development costs.
- Updates to crude oil and natural gas resource estimates for emerging shale plays.
- Addition of play-level resource assumptions for tight gas, shale gas, and coalbed methane
- Updates to the assumptions used for the announced/nonproducing offshore discoveries.
- Revision of the North Slope new field wildcat exploration wells (NFW) drilling rate function. The NFW drilling rate is a function of the low-sulfur light projected crude oil prices and was statistically estimated based on Alaska Oil and Gas Conservation Commission well counts and success rates.
- Recalibration of the Alaska oil and gas well drilling and completion costs based on the 2007 American Petroleum Institute Joint Association Survey on Drilling Costs.
- Updates to oil shale plant configuration, cost of capital calculation, and market penetration algorithm.

The description of the lower-48 oil and gas supply module from OGSM documentation for AE02010 is provided as a part of this response and is also included in the complete OGSM documentation that is available on the EIA website.[13] The OGSM documentation for AE02011, which will reflect the changes summarized above, is currently being prepared, and is scheduled to be released by the end of July 2011.

The key assumptions underlying the AE02011 are published in the AE02011 Assumptions Document (Oil and Gas Supply Module).[14] A comparison of the play-level resources assumptions between AE02011 and AE02010 is provided in the following table (Table 1).

[13] http://www.eia.gov/FTPROOT/modeldoc/m063(2010).pdf(See attached Appendix F)

[14] http://www.eia.gov/forecasts/aeo/assumptions/pdf/oil____gas.pdf (See attached Appendix A.)

Table 1. Unproved Lower 48 Technically Recoverable Shale Gas Resources (trillion cubic feet)

Region	Basin	Play	AEO2011	AEO2010
Northeast	Appalachian	Marcellus – Developing	178	48
		Marcellus – Undeveloped	232	--
		Devonian - Big Sandy	7	8
		Devonian - Greater Siltstone	8	2
		Devonian - Low Thermal Maturity	14	4
	Illinois	Devonian - Cincinnati Arch	1	1
		New Albany	11	3
	Michigan	Antrim	21	10
Gulf Coast	TX-LA-MS Salt	Haynesville	80	72
	Western Gulf Coast	Eagle Ford	21	18
	Black Warrior	Floyd-Neal/Conasauga	4	--
Midcontinent	Arkoma	Fayetteville – Central	30	26
		Fayetteville – West	5	3
	Anadarko	Woodford – Western	20	16
		Woodford – Central	9	6
Southwest	Fort Worth	Barnett – Core	35	29
		Barnett – Extension	20	16
	Permian	Barnett-Woodford	32	14
Rocky Mountain	Greater Green River	Hilliard-Baxter-Mancos	4	
	San Juan	Lewis	12	18
	Uinta	Mancos	21	
	Williston	Shallow Niobrara	7	4
	Undiscovered		15	--
West Coast	Undiscovered		41	51
TOTAL UNPROVED			827	349

For every *AEO* development, key assumptions and methodology are evaluated against existing data, including latest resource assessments from the USGS and the BOEMRE. As more information is gained through drilling and production realization, revisions to key assumptions (including shale gas resource estimates) and methodology may become necessary to keep current in this ever changing industry.

Question 4. Please list any outside contractors used in formulating EIA's projection of future U.S. natural gas production used in the AE02011 and all other agency reports or publications centering on shale gas; the criteria used for selecting those specific outside contractors; all correspondence (including reports, emails, memos, phone or meeting minutes or other materials) between EIA staff and any outside contractors regarding projections of future U.S. natural gas production; all internal EIA staff correspondence (including reports, emails, memos, phone or meeting minutes or other materials) relating to uncertainties in projections of future U.S. natural gas production.

Answer. The AE02011 oil and natural gas production projections are developed within the Office of Petroleum, Natural Gas, and Biofuels Analysis which is within the ERA's Office of Energy Analysis. Analysts and managers meet weekly to review and discuss the latest runs and the assumptions driving these results. Contractors contribute to the development of oil and natural gas input data and estimation parameters but are not part of the run review process. In addition, EIA holds working group meetings to solicit comments/suggestions pertaining to key assumptions and preliminary results. Participants in these working group meetings have been from other offices within the U.S. Department of Energy (DOE), the U.S. Environmental Protection Agency, USGS, NPC, industry, academia, consulting firms, oil and gas associations, National laboratories, and other government agencies.

The contractor used to assist in the development of AE02011 natural gas assumptions and data was SAIC. They chose to subcontract the shale gas resource assessment to INTEK under the EOP 3 task order previously discussed in the response to Question 2. INTEK's report to EIA, along with a brief EIA paper that summarizes and provides context for its findings, is available on EIA's website and is included in this response.[15]

The timing and level of production of natural gas resources, including shale gas, is determined within the National Energy Modeling System, primarily driven by the economics of drilling, rig availability, and demand. Although INTEK was instrumental instrumental in estimating the shale gas resource base, the conversion of these resources into production is modeled by EIA analysts. INTEK was not independently consulted but did participate in various working group meetings and workshops with attendees from other groups outside of EIA as previously indicated.

Question 5. According to The New York Times article, some of the outside contractors used by EIA to formulate estimates of natural gas reserves or projected levels of production have a financial or other interest in oil and/or gas companies or business relationships with such companies. Please provide details about each such contractor, the specific company and the nature of the interest or other relationship How does EIA ensure that all outside contractors conducting work for the agency do not have financial or other interests or relationships that could bias the results of any report? How does EIA ensure proper disclosure of any such interests?

Answer. EIA's contractual policies with regard to real and/or potential conflicts of interest are those prescribed by the Federal Acquisition Regulation (FAR). That is, the agency requires that contractors submit Organizational Conflict of Interest (OCI) documentation prior to any contract award to include:

- A statement of any past (within the past twelve months), present, or currently planned financial, contractual, organizational, or other interests relating to the performance of the statement of work.
- A statement that no actual or potential conflict of interest or unfair competitive advantage exists with respect to the advisory and assistance services to be provided.

This documentation is reviewed at the Departmental level by the relevant Contracting Officer, and the contract award itself is reviewed by DOE's Office of General Counsel to ensure that all pertinent rules are followed in the selection process.

Further, the prime contractor is required to obtain similar OCI documentation from all potential subcontractors and consultants and determine in writing whether the interests disclosed present an actual or potential conflict prior to issuance of a subcontract.

At the task order level, including the two task orders under which support was provided for the estimated natural gas resources, OCI documentation was again required in advance of an award being made.

Question 6. According to The New York Times article, some EIA staffers have reservations about the quality of the data provided by those contractors, specifically citing the use of press releases and media reports as a source of data. To what extent are EIA's projections based on press releases or media reports? What steps does the EIA follow to independently fact-check those press releases or media reports?

Answer. EIA's projections are not based directly on press releases or media reports. These sources are used to help inform where the industry focus is and where interest/development is heading. For example, an announcement of the major oil or gas discovery in the offshore Gulf of Mexico will direct analysts to check with the BOEMRE for confirmation and additional data needed to incorporate this new discovery into the model.

Data provided from contractors is reviewed and evaluated against other sources where available. Specifically, the shale gas resource base provided by INTEK for AE02011 was compared to recent estimates from other sources, some of which are summarized in slide 13 of a December 2010 presentation by Deputy Administrator Gruenspecht to the U.S.-Canada Energy Consultative Mechanism.[16] Drilling and completion costs are based on data provided by the American Petroleum Institute in their Joint Association Survey on Drilling Costs. Lease equipment and operating costs are based on EIA's lease equipment and operating cost estimates provided by the Office of Oil, Gas, and Coal Supply Statistics.[17]

To the extent possible, EIA uses resource assessments from USGS and the BOEMRE. The EIA uses contractors to provide assistance with updating resource estimates where development activities undertaken since the last available resource assessments by government agencies have added significant new knowledge. When

[15] http://www.eia.gov/analysis/studies/usshalegas/ (See attached Appendix G.)
[16] http://www.eia.gov/neic/speeches/gruenspecht12022010.pdf (See attached Appendix H.)
[17] http://www.eia.gov/pub/oil____gas/natural____gas/data____pub1ications/cost____indices____equipment____production/current/ coststudy.html (See attached Appendix I.)

the USGS and BOEMRE release updated resource assessments, these estimated resources replace the resource estimates developed by the EIA.

Recognizing that publicly announced production rates tend to be skewed toward high-production and high-profit wells, the EIA and its contractors use State reported well production where available to compare to publically available data and to calibrate engineering-based production curves. To project production from emerging or undeveloped areas with little to no drilling, EIA and its contractors use experience from other plays of similar nature as analogs. Thus, there is a great deal of uncertainty underlying the production projections. The EIA highlights the shale gas resource uncertainty in an AEO2011 Issues in focus article titled "Prospects for shale gas" and presents the impact of higher and lower shale gas resource assumptions on production, consumption, and prices.[18]

Question 7. Among the documents published by The New York Times are emails in which EIA officials express concern about the financial stability of shale gas companies and the economic viability of shale gas production. For example, one EIA official says "It is quite likely that a lot of these companies will go bankrupt" Another describes "irrational exuberance" around shale gas production. Can you please elaborate on those concerns? If shale gas is more expensive to produce than previously understood, how will the EIA's projections about natural gas supply and consumption be affected?

Answer. As noted in EIA's response to a pre-publication inquiry from the author of the June 27th NYT article[19], the continuing discussion regarding shale gas among EIA staff at all levels is a part of a healthy analytical process that considers both the shorter term dynamic of the industry and the longer term implications. Also, as your question references emails published on the NYT website that were selectively redacted, you may find the more complete versions that are provided with this response of some interest.[20] Those emails are largely to and from an individual who came to EIA as an intern in 2009 helping develop materials for a shale gas website and was subsequently hired as an entry-level employee in a position that did not involve responsibility for the development of EIA's energy projections. Some of redactions in the emails published on the NYT website obscure this context.

Ultimately, the profitability of shale gas development is a function of the costs required to drill and produce the gas and the price of natural gas. Over the last five years, wellhead natural gas prices have demonstrated considerable variability, rising well above $10 per thousand cubic feet in July 2008 and falling below $3 per thousand cubic feet in September 2009. Future natural gas prices and producer profitability have an impact on how much shale gas is produced and consumed in the different cases that are included in AEO2011.

As also noted in EIA's response to a pre-publication inquiry from the author of the June 27th NYT article, the uncertainty surrounding shale gas resources and the cost of developing them is explored in a section of the AE02011 entitled: "Prospect for shale gas," that is referenced in EIA's response to Question 6 and included in this enclosure as Appendix J. That analysis notes That "There is a high degree of uncertainty around the [AEO2011 Reference case] projection, starting with the estimated size of the technically recoverable shale gas resource. Estimates of technically recoverable shale gas are certain to change over time as new information is gained through drilling and production, and through development of shale gas recovery technology." The article then delineates 5 specific uncertainties associated with shale gas resources and costs. The analysis goes on to discuss 4 alternate case projections, which double and halve the resource base and the shale gas production cost per well. The variation in alternatecase assumptions is consistent with the degree of resource variability shown in USGS shale gas resource assessments. Across the 4 alternate shale gas cases, considerable variation is projected in domestic shale gas and total natural gas production, natural gas imports, natural gas prices, and natural gas consumption.

As noted in the response to Question 1, as additional information becomes available, EIA will change its assessment of domestic oil and gas resources and the cost of producing those resources.

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[18] http://www.eia,gov/forecasts/aeo/pdf/0383(2011).pdf, pages 37-40. (See attached Appendix J.)
[19] http://www.eia.gov/pressroom/releases/pdf/shale____gas.pdf. (See attached Appendix K.)
[20] See attached Appendix L.